

INCREASE IN FOSSIL FUEL UTILIZATION IN THE TWENTY-FIRST CENTURY: ENVIRONMENTAL IMPACT AND LOWER CARBON ALTERNATIVES

Hal Gluskoter
MS 956 National Center
U.S. Geological Survey
Reston, VA 20192

Keywords: fossil fuel, environment, economic growth

INTRODUCTION

Interest in the utilization of fossil fuels has greatly increased during the past few years; not because of the benefits to be derived from the energy produced, but rather because of the concerns related to the continued increase of emissions of greenhouse gases and their potential relationship to global climate change. It is generally recognized that there are trade-offs between the benefits to society that accrue from economic development and the possible ecological and environmental degradation brought about by that development. Within the next half century, the world's population will increase and, in order to serve the needs of growth and economic development, energy production will necessarily increase by a significant amount. The means by which the world will simultaneously resolve the dilemma posed by increased population, demand for energy, and concern for the environment will greatly impact the quality of life for most of the people on Earth.

POPULATION

The most recent biennial revision of population estimates and projections of the United Nations Population Division (1998) shows the rate of increase in the world population to be slowing. The current world population is 5.9 billion persons and the medium fertility projection, which the U.N. authors consider most likely, is for the world population to reach 8.9 billion in 2050. That is somewhat lower than previous projections. This slowing of the rate of population increase is the result of two factors; one of which most people would consider positive and the other negative. The global fertility rates have decreased in the past 50 years from five births per woman to the current level of 2.7 births. Although, the decline in fertility is worldwide, it is most pronounced in the developed countries, many of which have birth rates below that necessary to maintain a stable population.

The second factor affecting the rate of population growth is the devastation brought about by the epidemic of HIV/AIDS in much of the world, especially Africa. According to the United Nations Population Division report (1998), the 29 hardest hit African countries have average life expectancies that are seven years less than they would have been in the absence of AIDS.

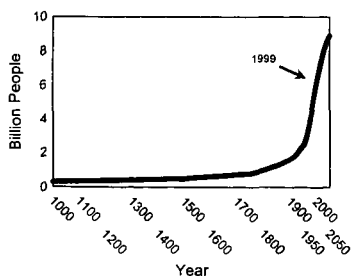


Figure 1. World population, 1000 - 2050, United Nations 1998 Revision of the World Population Estimates and Projections.

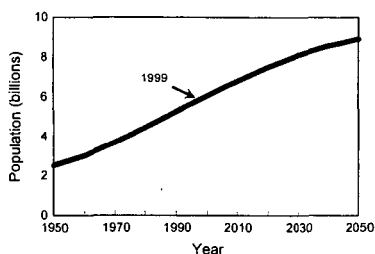


Figure 2. World Population, 1950 - 2050, United Nations 1998 Revision of the World Population Estimates and Projections.

The pattern of growth in the world population from the year 1000 AD projected to 2050 (figure 1)

is what one might expect from a living organism, and the population total is increased by an additional billion people every 12 to 13 years. The future does not appear as desperate if only one segment of that curve, from 1950 to 2050, is considered (figure 2). The world population will increase 50 percent over the next 50 years, primarily in Africa and Asia, accompanied, in these regions, by a significant trend to increased urbanization. The underdeveloped countries have a rate of urbanization that is 3.5 times that in developed regions (World Resources Institute, 1996, p. 1).

POPULATION AND ENERGY CONSUMPTION

Historically, a growth in world population has been accompanied by an increase in demand for energy. From 1970 to 1990 the total world commercial energy consumption increased 59 percent while the world population was increasing 43 percent (figure 3). Commercial energy includes energy

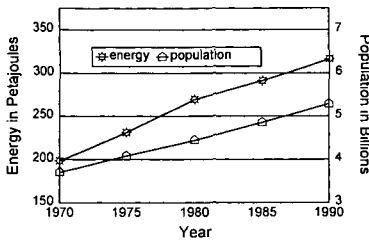


Figure 3. Growth in world population and world energy consumption, 1970 - 1990. Data from World Resources Institute, 1996, World Resources 1996-97, files HD 16101 and 21201.

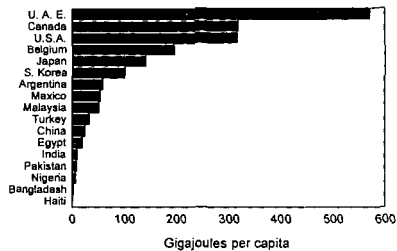


Figure 4. Commercial energy consumption, per capita, for selected countries. In gigajoules per capita. Source: World Resources Institute, 1996.

from solid, liquid, and gaseous fuels and primary electricity (hydroelectricity, nuclear, solar, wind, etc.), but does not include traditional fuels such as wood, charcoal, and animal wastes.

Population, alone, is not an accurate predictor of energy consumption. That is because there is a wide range in energy consumption per capita between the developed, developing, and undeveloped countries (figure 4). On a worldwide basis, the mean annual per capita energy consumption is 59 gigajoules (1 gigajoule = 947,800 Btu). However, the median per capita value is much lower than 59 gigajoules because the developed nations consume energy at a rate that is one or two orders of magnitude greater than that of the developing countries. For example, Mexico, Malaysia, and Argentina have per capita energy consumption near the mean value (59, 52 and 60 gigajoules, respectively) and the per capita consumption in the United States and Canada is 317-319 gigajoules. At the lower end of the scale are Nigeria (7 gigajoules), Bangladesh (3 gigajoules), and Haiti (1 gigajoule)(World Resources Institute, 1996 data table 12.2).

If we were to project energy consumption in the year 2050 based upon population alone it would increase 50 percent, the same amount as the population increase. However, the population growth will be mainly in countries in which the energy use is below the mean for the world. The 10 countries projected to have the largest national populations in 2050 are, in descending order, India, China, United States, Pakistan, Indonesia, Brazil, Nigeria, Bangladesh, Ethiopia, and the Democratic Republic of the Congo (United Nations, 1998). If they were to keep their per capita energy consumption constant during the next 50 years, they would only utilize 140 percent of their current energy in 2050. If the United States were to continue using energy at the current rate and the other nine countries were to increase their rate to that of Spain (85 gigajoules per capita), then the ten largest countries in 2050 would increase their energy consumption to 395 percent of that used today. Spain was chosen because it is at the lower end of energy consumption per capita of the countries in Europe.

India is projected to have the largest national population in 2050 with more than 1.5 billion people and China will be nearly as large (United Nations, 1998). These two countries currently utilize coal as the primary source of commercial energy. India uses five times as much energy from coal as from liquid fuels and China four times as much (World Resources Institute, 1996, data table 12.1). It is reasonable to assume that these two countries will continue using their indigenous coal resources as their primary fuel for electricity generation as their populations increase and, hopefully, their economies grow.

The Gross Domestic Product (GDP) is an economic indicator that correlates with many parameters considered to be associated with standard of living or quality of life. Darmstadter and Lile (1997) analyzed data from 114 countries in the world and found that there was a good positive correlation with adult literacy rate, life expectancy, and percentage of the population with access to sanitation. They concluded that GDP is a useful tool for evaluating key contributors to standard of living. Economists have adopted a form of GDP that allows for comparison of a currency's purchasing power within its own country. This is GDP based on "Purchasing Power Parity" or PPP and it represents the amount of a common "market basket" of goods each currency can purchase locally. It is that form of GDP (per capita) used in this paper.

Examples of parallel growth of GDP and energy consumption in two countries experiencing rapid

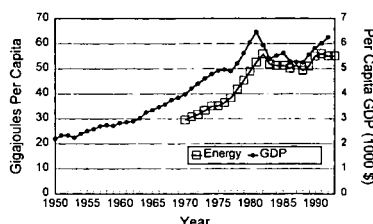


Figure 5. Per capita GDP and energy consumption per capita in Mexico, 1950 - 1993. Data from World Resources Institute, 1996, World Resources 1996-97, data files EI 15124 and EM 21202

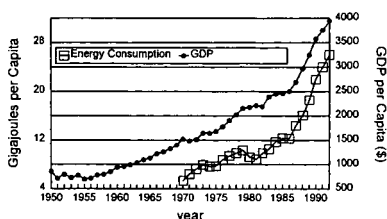


Figure 6. Per capita GDP and energy consumption per capita in Thailand, 1950 - 1993. Data from World Resources Institute, 1996, World Resources 1996-97, data files EI 15124 and EM 21202

economic development are shown in figure 5 and figure 6. From 1970 to 1992, the per capita energy consumption in Mexico increased 86 percent and the GDP increased 57 percent. During the same time period, a per capita increase in GDP in Thailand of 160 percent was accompanied by an increase in energy consumption of 387 percent. Because of the correlation between economic development, expressed as GDP, and energy consumption, it is reasonable to use GDP as a proxy for energy usage. There have been a few cases in which the rate of increase in GDP in a country has been greater than the rate of increase in energy consumption and therefore the proxy would not be valid. That has occurred only in highly developed countries with high GDP. One example is the response of the United States economy to increased energy prices of the 1970's (figure 7) and the continuing conservation efforts in what had been a profligate energy consuming economy.

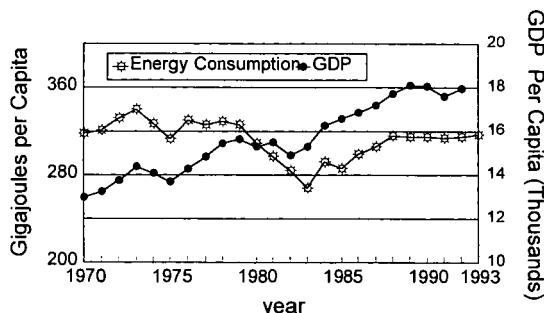


Figure 7. Per capita GDP and energy consumption per capita in the United States, 1970 - 1993. Data from World Resources Institute, 1996, World Resources 1996-97, data files EI 15124 and EM 21202

ECONOMIC GROWTH AND THE ENVIRONMENT - KUZNETS CURVES

The environmental Kuznets curve, named for Nobel laureate economist, Simon S. Kuznets, plots the relationships between environmental quality factors and per capita income. Seldon and Song (1994) looked at sulfur dioxide, suspended particulate matter, carbon monoxide and nitrogen oxides in a multi-national study. Grossman (1995) plotted Kuznets curves for sulfur dioxide and suspended particulate matter on a multi-national basis, and also analyzed suspended particulate matter, airborne

lead, sulfur dioxide, carbon monoxide, and nitrogen dioxide on a county basis for the United States. Shafik (1994) developed curves for the following ten environmental parameters: lack of safe water, lack of urban sanitation, annual deforestation, total deforestation, dissolved oxygen in rivers, fecal coliform in rivers, suspended particulate matter, ambient sulfur dioxide, municipal solid waste per capita, and carbon emission per capita.

Environmental Kuznets curves commonly exhibit one of three shapes. The first represents an environmental benefit that increases continually with increasing per capita income, an example of which is lack of safe water (figure 8). In this case, Shafik (1994, p. 761) explains that the benefits to individuals are high (survival is at stake) and the costs of provision are fairly low. Figure 9 exhibits the second shape, showing a continuous increase with rising incomes. This example, carbon emissions per capita represents current practice and only reinforces the concerns as to fossil fuel

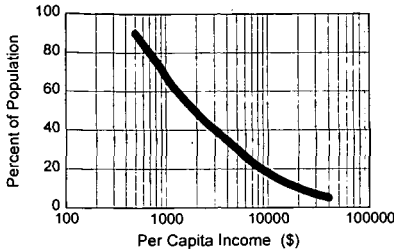


Figure 8. Lack of safe water and per capita income (per capita GDP). After Shafik, 1994, p.764.

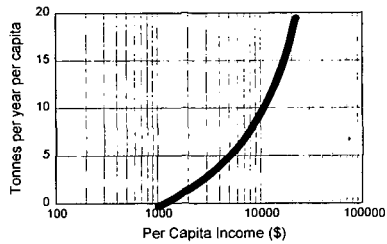


Figure 9. Carbon emissions per capita and per capita income (per capita GDP). After Shafik, 1994, p.764.

combustion.

The Kuznets curve that has received the most interest and has elicited the most discussion has an inverted 'U' shape and it has been used to predict air quality as related to economic development (figure 10). The inverted 'U' shape indicates that outdoor air pollution, including sulfur dioxide and suspended particulate matter, increases in the early stages of a nation's development, eventually reaches a maximum, and then declines as per capita income continues to increase. Similar shape curves have been reported for these two air pollution factors by three sets of researchers, although they reported different levels of income for the 'turning points'. Grossman (1995) calculated that the turning point for both factors was approximately \$5000 (1985 US); Shafik (1994) placed the top of the curves between \$3000 and \$4000; and Selden and Song (1994) calculated much higher values, \$8700 for sulfur dioxide and \$10300 for suspended particulate matter.

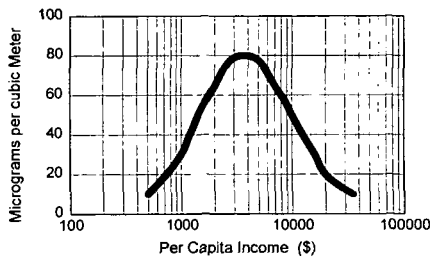


Figure 10. Ambient sulfur dioxide and per capita income (per capita GDP). After Shafik, 1994, p. 764.

The inverted 'U' shaped Kuznets curve could be interpreted to suggest that some environmental impacts of economic development are not serious because they will decline over time. Environmental degradation can be offset at a cost - scrubbers on power plants, for example - and increased per capita income gives nations the wealth with which to afford the cost. Technological developments and increase in the rate of technology transfer from the developed to the developing countries could accelerate the rate of improvement of environmental quality and allow for improvements in air quality to take place at lower per capita income levels than predicted from the historical data.

Not all economists are as sanguine about the concept of the Kuznets curves as the preceding paragraph might suggest. Stern and others (1996) summarized the current literature and critically

reviewed the concept of the environmental Kuznets curve. Among the points they and others (Arrow and others, 1995) make is that the data are analyzed by country and do not take into consideration international trade and the possibility that wealthier countries are "exporting" their environmental problems to less developed countries. Criticism of the Kuznets curves is in how they are interpreted; their usefulness as a descriptive tool is generally accepted. Most recently, the entire May 1998 edition of "Ecological Economics", the journal of the International Society for Ecological economics, edited by Rothman and de Bruyn, was devoted to the environmental Kuznets curve. Six articles explored the structural factors (in economic terms) that might relate to the empirically observed relationships between income levels and measures of environmental impact. The authors of these articles generally conclude, from quite varied analyses, that the interpretation of the environmental Kuznets curve is more complicated than the simple observation that economic growth is good for the environment. Most of the previous researchers had also stated similar positions.

ALTERNATIVE ENERGY SOURCES

In an essay entitled "The Liberation of the Environment", Ausubel (1996) observed that there are two central tendencies that define the evolution of the energy system. One is rising efficiency and the other is that the system is freeing itself from carbon (see also Nakicenovic, 1996). For the past two hundred years the world has progressively undergone decarbonization as the most desirable fuels for energy generation evolved from wood to coal to oil and then to gas. The truly desirable element in these fuels is not the carbon they contain, but rather their hydrogen. The global rate of decarbonization, as measured by the amount of carbon per unit of primary energy produced, has decreased by 40 percent in the past century. Ausubel (1996) suggests that "...over the next century the human economy will squeeze most of the carbon out of its system and move, via natural gas, to a hydrogen economy." The displacement of carbon will be a huge environmental and economic challenge. Globally, the per capita use of carbon is 1000 kilograms per year (Ausubel, 1996).

More than two thirds of the primary fuels currently consumed in the world is used to produce electricity, twice the share of 50 years ago. But, there are still two billion people in the world - one third of the population - without access to electricity (Ausubel, 1998). The installed electricity capacity of the world is predominantly thermal (coal, gas, and oil) with hydroelectric and nuclear power contributing significant amounts. Geothermal, wind, solar, biomass, photovoltaic and other "renewable" sources make up less than one percent (figure 11). The United States leads the world in the use of renewables for generating electricity, comprising 80 percent of the world's total. Proponents of renewables for generating electricity take some encouragement from the double-digit

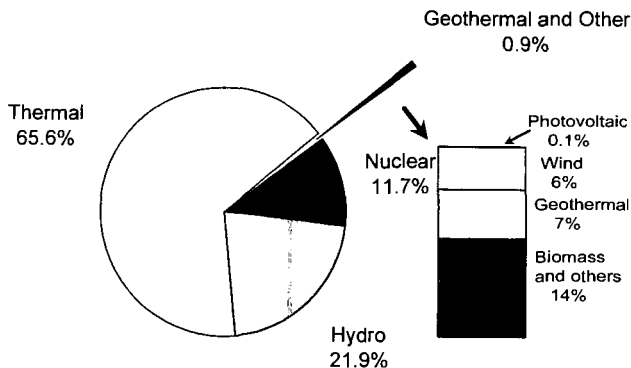


Figure 11. World electricity installed capacity and renewable energy sources used for generating electricity - 1996. From EIA, International Energy Annual, 1998, and Brown, and others, 1997

growth in global shipments of photovoltaic cells (O'Meara, 1997) and in a similar growth rate in global wind power generating capacity (Flavin, 1997). However, there will necessarily have to be much larger absolute increases in generating capacity from wind and solar before they have a significant impact on the world's totals. Currently, photovoltaics produce 0.003 percent of the world's electricity and wind produces 0.2 percent.

CONCLUSION

The challenge is great and may not be met. However, technological changes can transform society in a matter of decades. Ausubel (1996) uses the example of the electric lamp, which was invented a little more than 100 years ago. The modern version of that lamp is 90 times as efficient as the original. Nuclear energy as a source of generating electricity did not exist half a century ago and now represents 12 percent of the world's installed capacity and accounts for 77 percent of the electricity produced in France. Looking ahead 50 years to the future is much more challenging than reviewing the past. But it is certainly not out of the realm of the plausible to imagine an energy regime that has not only evolved beyond fossil fuels but has done so before the current coal, oil, and gas resources are exhausted.

REFERENCES

- Arrow, K., Bolin, B., Constanza, R., Dasgupta, P., Folke, C., Holling, C. S., Jansson, B., Levin, S., Maler, K., Perrings, C., and Pimental, D., 1995, *Economic Growth, Carrying Capacity, and the Environment: Science*, v. 268, p. 520-521.
- Ausubel, J. H., 1996, *The liberation of the environment: Daedalus*, v. 125, no.3, p.1-17.
- Ausubel, J. H., 1998, *Resources and environment in the twenty-first century: Seeing past the phantoms: World Energy Council Journal*, July 1998, p. 8-16.
- Brown, L. R., Renner, Michael, and Flavin, Christopher, 1997, *Vital Signs 1997: Worldwatch Institute*, 165p. Data tables also available on "Database Disk - January, 1998".
- Darmstadter, Joel and Lile, Ron, 1997, *GDP: Does It Matter: Resources*, published by Resources For The Future, issue 127, p. 6.
- Energy Information Agency, 1998, *International Energy Annual, 1996: DOE/EIA-0219(96)*, 244p.
- Flavin, Christopher, 1997, *Wind power growth continues: in Brown, L.R., Renner, M., and Flavin, C., eds, Vital Signs, 1997, Worldwatch Institute*, p. 52-53.
- Grossman, G. M., 1995, *Pollution and growth: What do we know?: in The Economics of Sustainable Development*, Goldin, I. and Winters, L.A., eds., Cambridge University Press, p. 19-50.
- Nakicenovic, Nebojsa, 1996, *Freeing energy from carbon: Daedalus*, v. 125, no. 3.
- O'Meara, Molly, 1997, *Cell shipments keep rising: in Brown, L.R., Renner, M., and Flavin, C., eds, Vital Signs, 1997, Worldwatch Institute*, p. 54-55.
- Rothman, Dale and de Bruyn, Sander, 1998, eds, *Special Issue, The Environmental Kuznets Curve, Ecological Economics*, v. 25, 229p.
- Selden, T. M. and Song, D., 1994, *Environmental Quality and Development: Is There a Kuznets Curve for Air Pollution Emissions?: Journal of Environmental Economics and Environmental Management*, v. 27, p. 147-162.
- Shafik, N., 1994, *Economic Development and Environmental Quality: An Econometric Analysis: Oxford Economic Papers*, v. 46, p. 757-773.
- Stern, D. I., Common, M. S., and Barbier, E. B., 1996, *Economic Growth and Economic Degradation: The Environmental Kuznets Curve and Sustainable Development: World Development*, v. 24, no. 7, p. 1151-1160.
- United Nations Population Division, 1998, *1998 Revision of the World Population Estimates and Projections: available online and to be published as World Population Prospects: The 1998 Revision and as a wall chart World Population 1998*.
- World Resources Institute, 1996, (jointly with United Nations Environment Program, United Nations Development Program, and the World Bank), *World Resources 1996-97: Oxford University Press*, 365 p. Data tables are also available as "World Resources 1996-97 Database Diskette",

WORLD ENERGY PROJECTIONS FROM THE INTERNATIONAL ENERGY OUTLOOK 1998

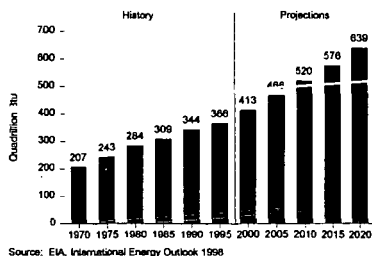
Linda E. Doman
Energy Information Administration
Washington, DC 20585

KEYWORDS: regional energy demand, forecasts, carbon emissions

The Energy Information Administration publishes the report, *International Energy Outlook (IEO)*, on an annual basis [1]. The report presents an assessment of world energy markets through 2020. The *Outlook* provides projections of total primary energy consumption, as well as projections of energy consumption by primary energy type (oil, natural gas, coal, nuclear, and hydroelectric and other renewable resources); and projections of net electricity consumption. By fuel projections of energy consumed for electricity generation and energy consumed at the transportation sector are also included. Carbon emissions resulting from fossil fuel use are derived from the energy consumption projections. All projections are computed in 5-year intervals through 2020.

In the 1998 edition of the *IEO*, we projected that by 2020, the world will consume three times the amount of energy it consumed in 1970 (Figure 1). Despite the economic crisis in Southeast Asia which began in the spring of 1997 and continued throughout 1998, we expect that almost half of the

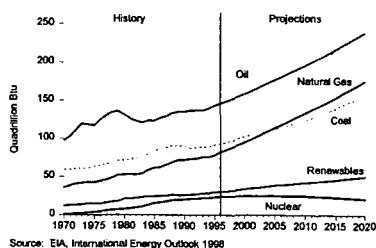
Figure 1. World Energy Consumption, 1970-2020



world's projected energy increment will occur in developing Asia. Indeed in our *International Energy Outlook 1998*, the reference case projections for Asia assumed the crisis in this part of the world would not be protracted and that the region will experience a return to the strong economic growth the region exhibited before the economic crisis. Energy demand levels should, therefore, return to the levels expected before the recession in the long run. By 2010, energy use in developing Asia (including China and India, but excluding Japan, Australia, and New Zealand) surpasses consumption in all of North America (comprised of the United States, Canada, and Japan) in our reference case. By 2020, developing Asia's consumption levels exceed that of North America by 36 percent (50 quadrillion British thermal units—Btu).

In the 1998 reference case forecast, world energy consumption reaches 639 quadrillion Btu, growing by 2.3 percent annually between 1995 and 2020. All sources of energy, except for nuclear power,

Figure 2. World Energy Consumption by Fuel, 1970-2020



grow over the projection period. Renewable energy sources do not grow as quickly in the forecast period as they have in the past 25 years (Figure 2). By 2020, the total increment in world energy consumption from the 1995 level is projected to be about 274 quadrillion Btu, representing a 75-percent increase in total energy consumption.

Much of the growth in energy consumption occurs outside the industrialized world—which today consumes about 86 quadrillion Btu more than the developing world. In fact, by 2005, nonindustrialized

countries (that is, the developing countries plus countries of Eastern Europe and the former Soviet Union) are expected to consume as much energy as the industrialized countries. But by the end of the forecast, energy consumption in the developing countries (developing Asia, the Middle East, Africa, and Central and South America) exceeds that of the industrialized world by 16 quadrillion Btu. Such large increases will have an enormous impact on the energy markets of the future. The projections assume substantial levels of new investment in all phases of energy production and distribution. To achieve such investment in many areas of the world, government policies must evolve, favoring private incentives for saving, trade, and development.

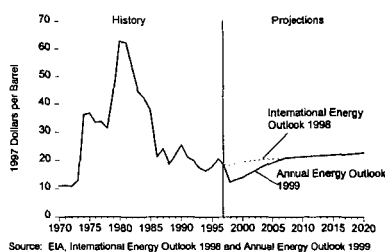
Reference Case Trends

World energy consumption is expected to reach 639 quadrillion Btu by 2020 according to our reference case projections. Much of the growth stems from increased fossil fuel use. Natural gas use is expected to have the fastest growth rate among the primary energy sources, at 3.3 percent per year between 1995 and 2020. However, the use of all fossil fuels is expected to grow faster over the next twenty-five years than it has in the past twenty-five years.

By 2020, oil consumption is expected to reach 116 million barrels per day, a 66 percent increase over the 1995 level. Oil has been the dominant energy source historically and is expected to remain so over the forecast period. However, oil demand is expected to grow more slowly than total energy consumption in the forecast, as it has for the past twenty-five years. In the industrialized countries, oil use continues to grow in the transportation sector where petroleum fuels have limited competition from other energy sources. In the rest of the world, oil demand is expected to grow in all economic sectors.

The worldwide growth in oil demand is expected to result in some increases in oil prices over the projection period. In the *IEO98* projections, prices rise from \$18 per barrel (U.S. 1996 dollars) in 1995 to over \$22 per barrel in 2020. The year-end 1996 price of oil was \$24 a barrel. General perceptions are that near-term price risks are more heavily weighted on the downside, rather than the upside; in 1998, many analysts lowered their near-term projections by \$1.00 or more per barrel for at least the next year or so, a sharp reversal of the views held early in 1997. In the *IEO98* forecast, prices were expected to recover from the lows experienced in early 1998. However, the recently released price path for our sister publication, the *Annual Energy Outlook 1999* suggest prices that do not recover until after 2005. Indeed, in the year 2000, world oil prices are more than \$5 per barrel lower in this year's *Annual Energy Outlook* than they were in last year's report (Figure 3) [2].

Figure 3. Comparison of 1998 and 1999 World Oil Price Paths



Source: EIA, International Energy Outlook 1998 and Annual Energy Outlook 1999

We expect oil prices to generally stay low because non-OPEC nations will be able to continue to expand oil production in the short-term. Improvements in technology associated with oil exploration, development, and production will allow the non-OPEC production to achieve these expectations. The use of three-dimensional seismic imaging, horizontal drilling, and subsea well completion technologies has helped to extend the productive life of mature oil fields and to reduce development and production costs at new fields. While the Middle East may

possess the largest portion of reserves that can be developed most economically, the reserves and production potential of other areas of the world have been substantially broadened. Nevertheless, OPEC producers are projected to gain share in the world oil production market, providing about 52 percent of the world's oil supply in 2020, compared to 39 percent in 1996.

Among all primary energy sources, natural gas is expected to grow the most rapidly, by 3.3 percent annually over the next 25 years. Natural gas resources are fairly widespread and burn more cleanly than other fossil fuels. This is particularly true in electric power generation where much of the future growth in gas demand is expected to occur. Moreover, combined-cycle gas-fired generators require shorter construction periods and are often more efficient than other fossil fuel generators or nuclear power plants. In the *IEO98* reference case projections, gas use surpasses coal by 2005, and by 2020 it exceeds coal demand by almost 18 quadrillion Btu (today, gas demand is about 13 quadrillion Btu less than coal).

There is much activity designed to expand the natural gas infrastructure worldwide. According to *Oil and Gas Journal*, in February 1997, 11,000 miles of gas pipeline were under construction and expected to be completed by the end of 1997, and over 34,000 miles of gas pipeline were planned for years beyond 1997 [3]. Natural gas demand is expected to grow most quickly in the developing world. In developing Asia, gas grows by 7 percent annually between 1995 and 2020. In Brazil alone, gas use increases by 14 percent annually in the reference case. There is robust activity in developing Central and South America's gas infrastructure needed to bring natural gas to industrial customers and electric generators. Construction began on several major pipelines in 1997, including work on the \$2 billion Bolivia-to-Brazil pipeline, the first portion of which is scheduled to be completed by the end of 1998, and the entire 1,973-mile line should be finished by the end of 1999

[4].

Worldwide coal consumption in the *IEO98* grows 1.7 times above the 1995 levels, reaching 8.6 billion short tons by 2020. The strongest growth in coal use occurs in Asia in the reference case projections. Indeed, nearly 90 percent of the increment in coal use is attributed to countries of developing Asia. What's more, 95 percent of the developing Asia increase is attributed to only two countries: China and India. In these two countries, coal continues to be the major primary fuel source. Outside of China, almost all of the increase in coal use will be for electricity generation.

Coal's role in energy use worldwide has shifted substantially over the past twenty-five years, from a fuel used extensively in all end-use sectors to one that is now primarily used for primary electricity generation, and in a few key industrial sector uses such as steel, cement, and chemicals. The coal share of total energy consumption decreases only slightly over the projection period, from 25 percent in 1995 to 24 percent in 2020, mostly because of the large increases projected in developing Asia. Coal use is shrinking in Eastern Europe and the former Soviet Union and this trend is expected to continue. Slow growth is projected in the industrialized countries where decreases in coal used in Western Europe offset gains in Japan and North America. Of course, the relatively stable outlook portrayed for coal in the *IEO98* could change dramatically as a result of the reductions in carbon emissions targeted in the Kyoto Climate Change Protocol. If the proposed reductions occur, the coal industry could face a rapidly declining market for its product in the years to come.

Nuclear power declines over the forecast horizon, and the source loses share of total energy consumption, falling from 6 percent in 1995 to 3 percent by 2020. At the end of the projection period, electricity generation from nuclear energy falls below the 2,203 billion kilowatthours consumed in 1995. Use of nuclear energy peaks worldwide in 2005 at 2,368 billion kilowatthours, after which the United States and other countries with mature nuclear programs are expected to phase out the nuclear generation and retire nuclear capacity without replacing it. A substantial reduction in nuclear capacity is also expected in the former Soviet Union after 2010. Nevertheless, some countries—particularly Japan and some of the countries of developing Asia—have plans to increase their reliance on nuclear power for electricity generation.

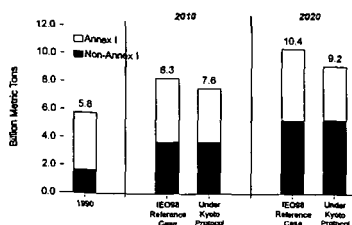
Nuclear power provided 17 percent of total electricity generation in 1996. In nine countries it provided more than 40 percent of electricity generation. Nevertheless, market competition from natural gas, public concerns about the safety of nuclear reactor operations, and problems associated with the disposal of nuclear waste products are constraining the expansion of nuclear power programs in many countries. The widespread trend towards privatization and deregulation of the electric utility sector has also undermined the viability of the nuclear option, because of the high costs associated with constructing and operating nuclear facilities. It is possible, however, that ratification of the Kyoto Protocol could change the outlook for nuclear power. Industrialized countries could conceivably extend the lives of their nuclear power plants in an effort to constrain the growth of greenhouse gas emissions.

Hydroelectricity and other renewable energy resources are expected to retain their 8-percent share of the world energy markets throughout the forecast period. Low fossil fuel prices make it difficult for renewables to compete for market share—despite the progress that has been made to reduce the per kilowatthour costs associated with generating electricity with renewables, particularly wind. In the reference case, renewables grow by 67 percent worldwide, with strongest growth projections in the developing world. There are some efforts in the industrialized world to increase the penetration of renewable energy sources to help mitigate the growth of greenhouse gases. In particular, the European Union announced a stimulus package for encouraging renewables, and plans to invest about \$11 billion in wind plants in hopes of installing 10 gigawatts of wind capacity by 2010 [5].

In the *IEO98* reference case, world carbon emissions are expected to reach 8.3 billion metric tons by 2010 and 10.4 billion metric tons by 2020. According to this projection, world carbon emissions would exceed 1990 levels by 81 percent at the end of the forecast period. By 2010, emissions in the developing world are projected to be almost equal to those of the industrialized nations with 78 percent of the world's increment in emissions between 1990 and 2010 attributed to the developing countries. If the Annex I countries¹ that are parties to the Kyoto Protocol were able to achieve the proposed target reductions, the forecast for their emissions would be altered; but emissions levels

¹The Annex I countries are defined as: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, European Economic Commission, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russia, Slovakia, Slovenia, Spain, Sweden, Switzerland, the Ukraine, the United Kingdom, and the United States.

Figure 4. Carbon Emissions in 1990, 2010, and 2020 in Two Cases: Annex I vs. Non-Annex I



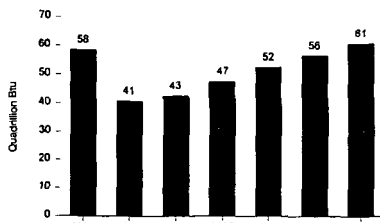
Source: EIA, International Energy Outlook 1998

region's developing markets. The Asian crisis did lead to some short-term reductions in the expectations for energy use in this region in the 1998 *Outlook*. If the crisis does not soon show some signs of abating in Southeast Asia, it could have a deepening affect on the growth in energy use in developing Asia. Thailand, Indonesia, Malaysia, and South Korea currently account for just less than 20 percent of the energy use in developing Asia. The recession has already caused energy projects to be either delayed in those countries, and a quick economic recovery is key to support their completion.

Another development which could have a dramatic affect on the growth in energy consumption worldwide is the Kyoto Climate Change Protocol. No adjustments were made to the projections of energy demand based upon the effects of the Kyoto Protocol because the *IEO98* was developed based on current laws and regulations in place. While some 60 countries have signed the Protocol (including the United States, although this occurred many months after the *IEO98* was published in November 1998 [6]), only Fiji and Antigua and Barbuda have ratified the treaty. None of the participating countries had ratified the treaty at the time our report was published. The Protocol will only become legally binding when at least 55 countries, including Annex I countries accounting for at least 55 percent of these countries' 1990 carbon dioxide emissions have signed and then ratified it.

The Kyoto Protocol could substantially affect energy use in the industrialized countries. For the emissions targets specified by the Protocol to be achieved solely through a reduction in fossil fuel use, projected energy demand in 2020 would have to be scaled by between 40 and 60 quadrillion BTU—equivalent to between 20 and 30 million barrels of oil per day. Of course, the reality is that fuel-switching opportunities, emissions trading permits, and other offsets allowed under the Protocol, such as reforestation will make a more modest reduction in fossil fuel use necessary.

Figure 5. Energy Consumption in the Former Soviet Union, 1990-2020



Source: EIA, International Energy Outlook 1998

Russia and the other countries of the former Soviet Union (FSU) pose a third challenge in terms of volatility in the forecast of energy demand. In the *IEO98*, energy consumption in the FSU only overtakes the 1990 level at the end of the projection period (Figure 5). This projection was published in April 1998, before the recent devaluation of the Russian rouble. Indications are that the economy has worsened in this region enough that the forecast may well need to be scaled back even further in our next report. Moreover, the *IEO98* projected that oil production in the FSU would increase to 12.6 million barrels per day by 2020, compared to an oil consumption of 7.5 million barrels per day in that same year. However, Russian First Deputy Prime Minister Yuri Maslyukov warned that unless serious actions were taken to "change the situation of the oil industry," Russia could become a net oil importer in as little as two years as the country's oil output has been in decline for the past ten years [7].

Future Considerations

As we prepare our next edition of the *International Energy Outlook*, we must address the levels of uncertainty we have about development of the world's energy markets given the events outlined above. Evaluating the long-term impact of the Southeast Asian economic recession, the length of

worldwide would continue to increase (Figure 4). Meeting the requirements of the Protocol exactly would mean a reduction of more than 700 million metric tons of carbon relative to the reference case forecast for 2010.

Uncertainty in the Forecast

At present, there are several areas which may be considered volatile in terms of trying to determine the future trends in energy demand. Asia is one, particularly given the recession that has remained in several key economies in the region—the largest being Japan, but also in the

time it will take the former Soviet Union—especially Russia—to recover from the collapse of their centrally planned economies, and the affects of the Kyoto Protocol on industrialized countries is a difficult task. Because regional gross domestic product (GDP) growth rates are one of two major assumptions we use to derive energy consumption projections (the other is an energy elasticity measure of the change in GDP divided by the change in energy consumption), adjusting economic growth will have a substantial impact on the growth in energy use. Growth expectations for GDP in Japan, the former Soviet Union, and countries in developing Asia will be somewhat reduced compared to last year's forecast. No doubt this will result in some reduction in the energy consumption forecast for these regions. In the *Annual Energy Outlook 1999*, the world oil demand projections showed a slight downward adjustment of 1.4 million barrels per day by 2020 from last year's *IEO*.

As of November 1998, none of the Annex I countries had ratified the Kyoto Protocol treaty so it is unlikely that this year's *IEO* reference case projections would be altered to incorporate the treaty. However, we expect to continue to address the potential effects the Protocol might have on various energy markets worldwide.

References

1. Projections that appear in this paper are taken from the Energy Information Administration, *International Energy Outlook 1998*, DOE/EIA-0484(98) (Washington, DC, April 1998).
2. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).
3. W.R. True, "World Pipeline Construction Looks to Remain Robust to Century's Turn," *Oil and Gas Journal* (February 10, 1997), pp. 36 and 37.
4. Brazil in Action web site (<http://www.brazil-in-action.gov.br>), "Bolivia-Brazil Gas Pipeline: Investment Opportunities," (July 22, 1998).
5. "European Union Maps Plans for Major Renewables Expansion," *Wind Energy Weekly*, Vol. 16, No. 776, (December 8, 1997), pp. 1-2.
6. United Nations Framework Convention on Climate Change Press Release, "Climate Change Meeting Adopts Buenos Aires Plan of Action," (November 17, 1998).
7. Itar-Tass via NewsEdge Corporation release (<http://www.newspage.com>), "Russia's Oil Output Mishandled - Maslyukov," (November 23, 1998).

COAL QUALITY AND COAL UTILIZATION IN THE TWENTY-FIRST CENTURY

R.B. Finkelman and H. Gluskoter

U.S. Geological Survey, MS 956, National Center, Reston, VA 20192

KEYWORDS: Coal quality, domestic databases, international databases

Abstract

Worldwide coal utilization in the 21st Century will be influenced by concerns about the effects of coal combustion on the local, regional, and global environment and on human health. Reliable coal quality data can help decision makers to better assess the risks and limit the possible environmental degradation and impact on health. Although millions of coal analyses have been performed worldwide, existing national coal quality databases are generally of limited use because much of the data are not readily accessible; geographic coverages are not comprehensive; analytical data may not be accurate; and samples may not be representative, or current. The U.S. Geological Survey is collaborating with agencies from other coal producing countries to create an integrated, electronic, worldwide coal quality database. The database, on coals currently being burned, includes results of proximate and ultimate analyses; sulfur form data; concentrations of major, minor, and trace elements; semi-quantitative analyses of minerals; and modes of occurrence of environmentally important elements.

Introduction

When the U.S. Congress passed the 1990 Clean Air Act amendments (1) worldwide attention was focused on the potential environmental and human health problems that could be caused by the emissions of hazardous air pollutants from coal-burning power plants. Among the potential pollutants were about a dozen trace elements including the elements, or compounds of, antimony, arsenic, beryllium, cadmium, chlorine, chromium, cobalt, fluorine, manganese, mercury, nickel, lead, selenium, and radionuclides (e.g. uranium and thorium) as well as scores of organic compounds. The U.S. Environmental Protection Agency, therefore, sought reliable, comprehensive coal quality information to help assess the potential environmental and human health impacts of these substances that might arise from coal use. These concerns may be with us well into the 21st Century as we learn more about the effects of long-term, low-level exposure to toxins.

Concerns about the environmental and health impacts of coal use are not constrained to the United States. Environmental and human health problems attributed to coal use have been documented from Czechoslovakia (2), China (3, 4), India (5), Ukraine (6), Russia, and elsewhere. The social cost of these problems is enormous and will continue to grow, especially in developing countries that tend to use poor quality coal in boilers with little or no pollution control systems or use coal for domestic cooking and heating.

The World Resources Institute (7) estimates that as many as 3.5 billion people rely on traditional fuels for cooking and heating. The World Bank (8) estimates that between 400 million and 700 million woman and children are exposed to severe air pollution, generally from cooking fires, a substantial proportion of these people rely on coal. The particulates, metals, gases (such as SO_x), and organic compounds (such as polycyclic aromatic compounds: PAC) can cause serious respiratory problems and toxic reactions.

While many of the environmental and health problems caused by coal use are local, some of the volatile pollutants (CO₂, SO_x, NO_x, Hg, Se, Cl, F) may have regional and even global environmental and human health impacts. Clearly these environmental and health problems create complex economic and social ills that will require carefully considered, multidisciplinary, 21st Century solutions. Reliable, comprehensive and readily available coal quality data can help decision makers to better assess the risks and limit the possible environmental degradation and impact on health.

Domestic Databases

Domestic databases of quality of coals in the United States, while incomplete, are available. The U.S. Geological Survey (USGS) maintains the largest publicly available coal quality database. The database contains information on almost 14,000 coal samples from every major coal basin in the U.S. Approximately 136 parameters are recorded for each sample. These parameters include geographical, geologic, and stratigraphic information, quantitative information on about 60 elements,

proximate and ultimate data, sulfur-form information, ash fusion temperatures, etc. Recently, much of this information has been made available on CD-ROM (9) and on the World Wide Web at URL <http://energy.er.usgs.gov/products/databases/coalqual/intro.htm>.

The Illinois State Geological Survey, the New Mexico Bureau of Mines and Minerals Resources, the University of North Dakota's Energy and Environmental Research Center (EERC), and the Pennsylvania State University also maintain high-quality, publicly available coal quality databases containing several hundred to more than 1,000 analyses.

A weakness of all the publicly available coal quality databases is that the samples represent coal that has been mined. For example, approximately 75 percent of the information contained in the USGS database was obtained prior to 1985. Twenty-first Century decisions will require information that reflects the characteristics of the coal that is currently being mined and burned and of the coal that will be mined in the near future. Moreover, current environmental concerns require new types of information to be included in these databases. For example, semi-quantitative analyses of minerals and modes of occurrence of environmentally important elements are necessary for the development of computer models to predict the behavior of these elements during coal cleaning and combustion. Petrographic characterization of coal may provide useful insights into the types and amounts of PAC's generated during domestic coal combustion (10).

To address these concerns, the USGS is teaming with other organizations to create a new coal quality database. This new database, known as the National Coal Quality Inventory (NaCQI) is supported by a partnership forged among federal and state governmental agencies, the utility and mining industries, and universities (11).

The project participants will collect suites of samples (core/channel, run-of-mine, raw/clean, power plant feed, etc.) from the major coal producing regions in the U.S. that will provide coal in the 21st Century. The samples will be characterized by traditional methods (12) for proximate and ultimate analysis, sulfur form data, major, minor and trace elements. The scope of this database will be broadened to include modes of occurrence information and semi-quantitative mineralogy on selected samples.

International Coal Quality Databases

Most of the growth in energy consumption in the 21st Century will be seen in developing countries such as China, India, and Indonesia, all of which have large indigenous coal resources (13). Increasing populations and rapid industrialization is placing enormous pressures on these countries to produce energy through increased coal use. With this rapid expansion of coal use comes the potential for serious environmental and human health problems. Unfortunately, many of these countries lack the reliable, comprehensive, electronic coal quality database needed to help minimize these problems.

Although millions of coal analyses have been performed worldwide, most existing national coal quality databases are generally of limited use because:

- Much of the data are in obscure publications, are in the native languages, or the data reside in paper files that are not readily accessible;
- Geographic coverages are not comprehensive;
- Analytical data may not be accurate or may be incompatible with analytical schemes used in other countries;
- The analyzed coal samples may not be representative of the full deposit, or the samples may have been collected and analyzed many years, often several decades, ago.
- Information is lacking on trace element concentrations, mineralogy, and modes of occurrence of the elements of environmental concern.

To help develop an integrated, electronic worldwide coal quality database, the USGS has initiated a unique compilation of coal quality information from all the coal-producing countries in the world. The database (World Coal Quality Inventory: WoCQI), will focus on information from coals currently being burned and will include results of proximate and ultimate analyses, sulfur form data, concentrations of major, minor, and trace elements, semi-quantitative analyses of minerals, and modes of occurrence of environmentally important elements on selected samples. The information in the database will be made available on the World Wide Web (WWW) and through a searchable CD-ROM.

The sources of coal quality information that will be incorporated into the database include capturing existing computerized databases and salvaging information from publications and hardcopy files. However, the highest priority will be given to developing cooperative agreements with representatives of coal-producing countries. In most agreements the host country will be responsible for the collection of the sample using appropriate sample collection protocols and the USGS would be responsible for sample characterization, database development, and information dissemination.

The information in the WoCQI database could be used to evaluate:

- National and regional energy resources
- Export/import potential
- Potential environmental and health impacts
- Technological behavior
- Technology transfer potential
- International Policy decisions
- Byproduct potential

WoCQI currently contains approximately 2,000 analyses from about 20 countries (exclusive of the U.S.). We intend to expand the scope of coal quality characteristics to include information on mineralogy, petrography, washability, modes of occurrence, etc.

We should strive to develop coal quality databases that anticipate the potential future uses of the coal quality data. This would require that 21st Century coal quality databases contain a broader range of coal quality parameters including quantitative information on modes of occurrence of the elements, semi-quantitative mineral composition, and information on the behavior of the elements during coal cleaning, leaching, and combustion.

In addition to addressing environmental and health problems, coal quality data can also be used to better anticipate technological problems such as boiler fouling, slagging, corrosion, erosion, and agglomeration. This, in turn, could lead to coal-blending or additives that would minimize these costly problems. Information on the textural relations (mineral-mineral and mineral-macerale intergrowths) should be useful in anticipating the removability of trace elements during physical, chemical, and biological coal cleaning. Anticipating the removability of certain elements from coal might create opportunities for economic byproduct recovery.

Coal quality data could play an important international role by providing useful information on potential foreign investment prospects. This information may also help to identify markets for coal industry goods and services.

Quantitative coal quality data, comprehensive databases containing a broader array of quantitative coal quality parameters, and multi-disciplinary, multi-organizational, and multi-national cooperation should help to ensure the efficient and environmentally compatible use of our global coal resources in the 21st Century.

References

1. U.S. Statutes at Large (1990) Public Law 101-549, Provisions for attainment and maintenance of national ambient air quality standards, 101st Congress, 2nd Session, 104, Part 4, 2353-3358.
2. Bencko, V. and Symon, K., 1977, Health aspects of burning coal with a high arsenic content. II. Hearing aspects of burning coal with a high arsenic content. Environmental Research, Vol. 13, p. 386-395.
3. Belkin, H E, Zheng, B, Zhou, D, and Finkelman, R B, 1997, Preliminary results on the geochemistry and mineralogy of arsenic in mineralized coals from endemic arsenosis areas in Guizhou, Province, P. R. China. Proceedings of the Fourteenth Annual International Pittsburgh Coal Conference and Workshop. (CD-ROM).
4. Finkelman, R. B. in press, Health impacts of domestic coal use in China, National Academy of Sciences colloquium on "Geology, Mineralogy, and Human Welfare.
5. Singh-Mahendra, P., Singh, R.M., Chandra, D., 1985, Environmental and health problems due to geochemical alterations associated with trace elements in coals, Ghugus Coalfield, Wardha Valley,

Maharashtra, Quarterly Journal of the Geological, Mining and Metallurgical Society of India. Vol. 57, no. 2, p. 99-103.

6. Panov, B.S., Shevchenko, O.A., Matlak, E.S., and Dudik, A. M., in press, On pollution of the biosphere in industrial areas: the example of the Donets Coal Basin. International Journal of Coal Geology.

7. World Resources Institute, 1998, World Resources 1998-1999. The World Resources Institute, New York. 369 p.

8. World Bank, 1992, The World Bank Development Report 1992: Development and the Environment, Washington, D.C., p. 53.

9. Bragg, L. J., Oman, J. K., Tewalt, S. J., Oman, C. L., Rega, N. H., Washington, P. M., and Finkelman, R. B., 1997, U.S. Geological Survey Coal Quality (COALQUAL) Database: Version 2.0, U.S. Geological Survey Open-File Report 97-134.

10. Crowley, S.S., Orem, W.H., Roth, M.J., Finkelman, R.B., Scroggs, E.A., Willett, J.C., 1998, Possible Relation Between Esophageal Cancer and Coal Combustion in China: A Preliminary Study: Abstracts of the 15th Annual Meeting of the Society for Organic Petrology, Vol. 15, p. 96-98.

11. Finkelman, R.B., 1996, The national coal quality inventory: An example of industry, federal and state cooperation: 13th Annual International Pittsburgh Coal Conference, vol. 1, p. 403.

12. ASTM (American Society for Testing and Materials), 1997, Annual Book of ASTM Standards. Volume 05.05 Gaseous Fuels; Coal and Coke, ASTM, Philadelphia, PA.

13. World Energy Council, 1993, Energy for Tomorrow's World. St. Martins Press, 320 p.

CURRENT AND FUTURE ISSUES FACING HIGH-SULFUR MIDWESTERN COALS

Subhash B. Bhagwat

Illinois State Geological Survey, 615 E. Peabody Drive, Champaign, IL 61820

INTRODUCTION

Coal markets have been dramatically affected by the Clean Air Act (CAA) and its many amendments, and by price competition among fuels and between coals of different quality. Regulations regarding electricity generation, distribution and pricing now being eliminated. International concerns about global climate change will affect coal markets in the future. This paper presents an analysis of how these and other factors have affected high-sulfur coals in the past and how they will affect them in the future.

DEMAND-SIDE ISSUES

Coal demand in the U.S. increased from 523 million tons in 1970 to 1007 million tons in 1997. Electric utilities accounted for 61% of domestic total in 1970, and 90 % in 1997. Coal-fired power plants generated 46 % of the electricity for the utilities in 1970 and over 57 % in 1997 ⁽¹⁾. Nuclear electricity generation increased from 1.4 % of the total in 1970 to 22.5 % in 1995, but fell to 20.1% in 1997 due to plant safety and maintenance problems. The oil and natural gas price shocks in 1974 and 1979-81 resulted in significant fuel switching by electric utilities. By 1997, oil and natural gas-based electricity generation had fallen to 2.5% and 9.1% of the total respectively, well below their 1970 levels of 11% and 24%. Electricity generated by non-utility producers contributed an additional 3 to 12 percent to total electricity generated by utilities (**Figure 1**). Available data indicate that natural gas is the preferred fuel of non-utility producers, thus increasing gas-based generation of electricity in 1997 to 14.5% of U.S. total. Growth in U.S. demand for electricity averaged about 4% per year in 1970, but declined to about 2% by 1997 (**Figure 2**). However, increased post 1990 non-utility generation resulted in slowing down growth in utility generation to 1% in 1997 (**Figure 3**).

In 1991, the U.S. Department of Energy and four other institutions forecasted U.S. electricity demand to grow at 1.4 to 2.4% per year from 1990 through 2010 ⁽²⁾. Subsequently published DOE Annual Energy Outlooks revised the forecast to 1.26% per year between 1995 and 2010 ⁽³⁾ ⁽⁴⁾, 1% per year for utilities and 3% for non-utility producers. These estimates indicate the continuation of the trends depicted in figures 2 and 3. Based on these forecasts, U.S. coal production in year 2010 is estimated to be about 1,225 million tons. Thermal conversion efficiency is a critical factor. A 1 percent increase in it can reduce coal demand by 2.5% or 30 million tons. Such a change is conceivable as less efficient, older plants are retired or their usage reduced.

REGULATORY ISSUES

Two sets of regulations affect coal markets: the Clean Air Act amendments (CAAA) of 1990 and the deregulation of the electricity generating industry. The potential for future regulation of "greenhouse gases" may already be affecting fuel choice decisions by utilities. The 1990 CAAA were the result of Congressional desire to create economic incentives and freer markets for pollution control. Accordingly, the mandatory 90% emission reduction was eliminated but a reduction in nation-wide SO₂ emissions of 5 million tons by January 1995 (Phase I) and another 5 million tons by January 2000 (Phase II) together with an overall cap on emissions at the year 2000 level were mandated. The mechanism to do this is the "pollution credit," which allows plants that reduce emissions below the legal limits to achieve a credit that they can sell to plants that are over the limit. Utilities in need of emission reduction can reduce emissions or purchase pollution credits in the market. The decision is to be made by individual companies on an economic basis. In the first phase of the 1990 CAAA that ended in 1995, a majority of plants opted for low-sulfur Wyoming coal or natural gas and created a large stock of pollution credits with few buyers. Consequently, the price of pollution credits fell from the originally predicted \$1,500 per unit (1 Unit = 1 ton of SO₂ per year) to \$65 to \$70 per unit ⁽⁵⁾ by March 1996. In October 1998, they were trading at \$160 to \$180 per unit ⁽⁶⁾.

To comply with the second phase of the 1990 CAAA, utilities have been switching to lower sulfur fuels for the past three years and an acceleration of the trend is likely in 1999. For example: Illinois Power, the largest consumer of high-sulfur coal in Illinois, has decided to

switch to Wyoming coal in the next twelve months. Because the delivered prices of low- and high-sulfur coals are comparable in most states, demand for western coal is expected to rise through the year 2000 and possibly through 2010. After 2000, sulfur-free fuels such as natural gas will be preferred by users who must comply with the SO₂ emission "cap". Available technologies like Flue Gas Desulfurization (FGD) and Fluidized Bed Combustion (FBC), and emerging ones like Integrated Gasification Combined Cycle (IGCC) would permit coal-burning with little or no SO₂ emission. Decisions to use them, however, will depend on their total generating cost compared with the total cost of using sulfur-free fuels.

Emissions of nitrogen oxides (NO_x) are also regulated under the Clean Air Act. Some NO_x rules apply only to plants that are affected by CAA SO₂ regulations. Each affected unit must hold NO_x emissions below 0.45 or 0.5 lbs per million Btu, depending upon the boiler type. Stricter limits apply to ozone non-attainment areas. States must determine what approach is reasonable to achieve this goal.

The 1990 amendments also propose to control emissions of Hazardous Air Pollutants (HAPs). When regulations are established, they may affect coal use because up to 16 HAPs are known to be released by combustion. Of these, mercury is likely to be one of the first to be regulated. Resource Data International (RDI) recently estimated the cost of curbing mercury emissions to range between \$0.5 billion and \$7.8 billion annually and add up to 0.2 cents to the cost per kWh of electricity ⁽⁷⁾. Mercury-free fuels would thus have an advantage over other fuels in the future.

Utilities have been "regulated monopolies." Customers within a utility's service area could only purchase electricity from that utility. A state commission determined the utility's rate of return on investment, and approved all expenses the company charged to consumers. Electric utilities are now being deregulated under the 1992 National Comprehensive Energy Policy Act. "Independent" unregulated power companies are now permitted. These independents are free to produce and sell electricity to anyone anywhere. Utilities are also now permitted to merge. Wholesalers who buy electricity for resale are free to purchase it anywhere, and utilities are required to provide transmission for a fair market charge. Retail customers, however, are still required to purchase electricity from the same utilities as before until state laws are amended.

Deregulation will likely intensify price competition among producers of electricity and force cost-cutting measures in the industry. Some of the consequences of the increased competition are as follows:

- *Old low-efficiency and high-cost generating units will be retired earlier than planned.
- *Lower-cost units will increase their capacity utilization (load factor).
- *Independent producers will not have price or sales guarantees.
- *Independent electricity distribution networks, including intra-city, may emerge.
- *Gas-fired combined-cycle electricity generation may assume a greater role in production.
- *Nuclear power plants may face economic hardships because of unrecovered investments, called the "stranded costs".
- *Rural electric power supply companies facing loan servicing problems may require federal assistance worth billions of dollars to avoid bankruptcies ⁽⁸⁾.

INTER FUELS COMPETITION

Coal availability in the United States is not a problem. According to DOE, recoverable coal reserves in the U.S. total about 265 billion tons. About 61 billion tons of the U.S. recoverable coal reserves are in the Interior Region and about 80% of that is in the Illinois Basin, which includes parts of Illinois, Indiana and western Kentucky. Thus, nearly 49 billion tons of recoverable coal reserves, or 18.5% of the national total, are in the Illinois Basin ⁽⁹⁾. However, the low-sulfur (<1.2 lbs SO₂ per million Btu) recoverable reserves in the U.S. are about 100 billion tons, very little of which is in the Interior Region. Little or no Illinois Basin coal can comply with the maximum allowable SO₂ limit through the year 2000 without additional cleaning or other forms of emission controls (**Figure 4**). About 87% of the nation's low-sulfur coal reserves are in the western states, while 61% of high-sulfur (>3.36 lbs SO₂ per million Btu) recoverable coal reserves are in the Interior Region, mostly in the Illinois Basin.

Fuel cost is the main determinant of generating plants' operating cost but fuel choice is determined not only by its price but also by the cost of equipment needed to burn it cleanly and to safely dispose of waste. In the short run, the additional equipment costs

disadvantage high-sulfur coal. In the long run, however, the deciding factor will be the cost of coal. To understand high-sulfur coal's current and near term disadvantage in comparison to other fuels, the cost of these fuels and the comparative costs of various pollution abatement strategies must be understood.

Pollution control and waste disposal costs of fossil fuels have been included in the price of coal-generated electricity, but the nuclear industry's costs of development and waste disposal have not been fully internalized, and insufficient money is being set aside to pay for the decommissioning of nuclear plants⁽¹⁰⁾. These un-internalized costs helped nuclear energy grow at exceedingly high annual rates in the past 25 years. Despite their low operating costs, nuclear plants are economically troubled by their stranded costs that must be recovered through higher rates, or borne by investors.

Gas-based generation increased at 2.4% per year during 1989 to 1995, after a sustained 16 year decline. Although gas based non-utility generation increased in 1996 and 1997, utilities used less gas than in 1995 with the result that total gas based generation remained unchanged. Delivered prices of natural gas to utilities increased 40 % in 1996-97. Gas fired power plants have important economic advantages because of their high thermal efficiency (60%) compared with coal-fired plants (40%). Gas-fired plants take only 1 to 3 years to build and cost at least 40% less than coal-fired plants⁽¹¹⁾. Unlike in the 1980s, gas is no longer perceived as a commodity in short supply. DOE estimates proven U.S. gas reserves to be about 165 trillion cubic feet (Tcf), the equivalent of ten years of supply at the current rate of production. Seven times more than that can be found and produced at current prices and with currently available technology⁽¹²⁾. Planned capacity additions by electric utilities indicate that of the 32,000 MW to be added between 1993 and the year 2000, about 60% will be gas-based and only 20% coal-based⁽¹³⁾.

According to the 1996 DOE annual energy outlook, the growth in coal-based electricity generation between 1995 and 2010 will come from an increase in capacity utilization from 62% to about 75%. No net addition to coal-based generating capacity is expected. Coal mined in the western states enjoys a price advantage over Midwestern coal primarily because mine productivity is high, mining costs are extremely low (Table 1), and because average nationwide rail transportation rates declined 17% between 1986 and 1993 as a result of the transportation industry deregulation in the late 1970s⁽¹⁴⁾. As a result of increased use of Wyoming coal, the federal EPA reports a 2.3 million unit (1 Unit = 1 ton SO₂) over-compliance in January 1995. With this, almost half of the reductions targeted in the 1995-2000 period have already been achieved. A further increase in the use of low-sulfur coal through the year 2000 is likely.

THE KYOTO AGREEMENT

In December 1997, over 140 nations met in Kyoto, Japan, to discuss the possible effects of carbon dioxide emissions on global climate. The agreement reached at that meeting requires industrialized nations to reduce carbon emissions to an average of 7 percent below the 1990 carbon emission level by the year 2010. Most developing countries are exempt from these requirements because their current contributions to carbon emissions are low. The effectiveness of the Kyoto agreement is questionable for two reasons: 1) Economic growth rates in developing countries are two to three times those in developed countries. Thus, in twenty years most carbon emissions would be coming from those countries. 2) A reduction of carbon emissions to pre-1990 levels in industrialized countries would require a drastic reduction in energy consumption starting immediately. Such reductions would disrupt the entire world economy and threaten the livelihood of billions, including those in the developing countries that depend on exports to industrialized countries. The combined effects of the factors discussed above on the future demand for various fuels are summarized in the following chart: (An upward arrow indicating higher, a downward arrow lower demand)

| | 1990 CAAA | Deregulation | Kyoto agreement |
|-------------|-----------|--------------|-----------------|
| Coal | | | |
| Low Cost | ↑ | ↑ | ↓ |
| High Cost | ↓ | ↓ | ↓ |
| Natural Gas | ↑ | ↑ | ↑ |
| Nuclear | ↓ | ↓ | ↑ (?) |

FUTURE OF HIGH-SULFUR COAL

The coal mining industry in the high-sulfur coal states has been hit hard by the dynamics of the coal market. High-sulfur coal production began to decline after the passage of the 1990 CAAA. Coal production in Illinois, Indiana, western Kentucky and Ohio declined by about 19 percent, from 176.5 million tons in 1990 to 143.3 million tons in 1997. Illinois coal production fell about 30%. Dozens of Illinois coal mines closed and over half the jobs were lost. Long-term sales contracts are declining rapidly. The future demand for high-sulfur coal will depend upon its price. The delivered prices of high-sulfur coals in most areas are higher than the prices of low-sulfur western coals. The conditions for high-sulfur coals in the first decade of the next century remain unchanged: slow growth in electricity demand, an even slower growth in coal-based electricity generation, and a higher price in comparison with low-sulfur western coal. Unfortunately, mine productivity in the high-sulfur coal states has not grown sufficiently to narrow the price gap. More power producers are opting for lower sulfur coals and natural gas. Under continuing prospects for lower coal production, the expected year 2010 production from Illinois, Indiana, western Kentucky and Ohio may be in the range of 100 to 105 million tons.

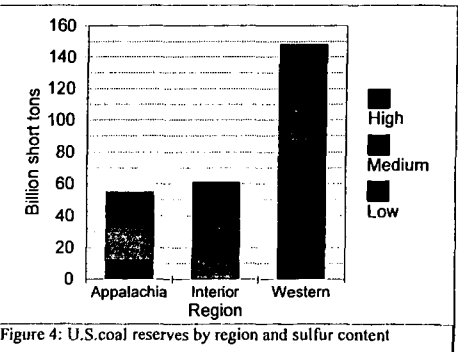
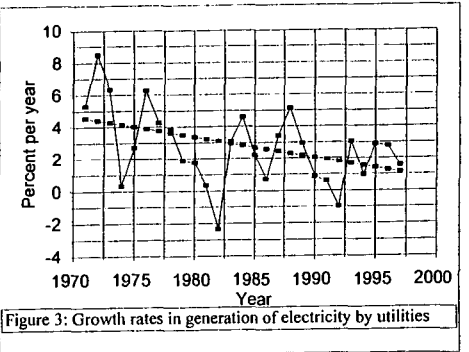
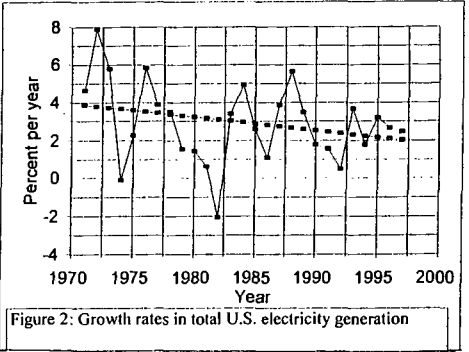
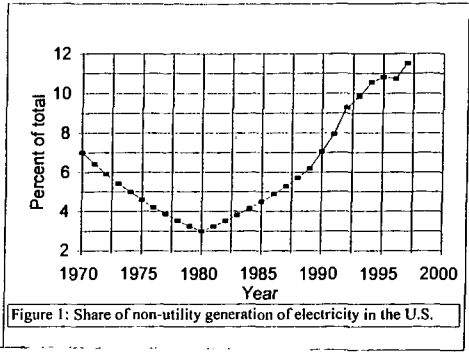
REFERENCES:

- (1)Monthly Energy Review, Jun.1998, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0035(98/06), page 95.
- (2)Annual Energy Outlook 1991 With Projections to 2010, March 1991, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0383(91), page 38.
- (3)Annual Energy Outlook 1993 With Projections to 2010, January 1993, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0383(93), page 49.
- (4)Annual Energy Outlook 1996 With Projections to 2015, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0383(96), pages 94 and 95.
- (5)EPA Credit Auction Shows mid-\$60 Prices; Announces Massive 1995 Over-compliance, Coal Week, April 1, 1996, pages 1 and 2.
- (6)Power Marketers Spiash into Allowance market, Todd A. Myers, Coal Age, October, 1998,
- (7)National Mining Association, November 9, 1998,
- (8) U.S.Giving Electric Co-ops Relief on Loans, The Wall Street Journal, October 3, 1996, p.A3-A4.
- (9)Coal Data: A Reference, February 1995, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0064(93), page 47.
- (10)Heinze Fry, Gene R. The Cost of Decommissioning U.S. Reactors: Estimates and Experience. The Energy Journal, International Association for Energy Economics, Special Nuclear Decommissioning Issue, Volume 12, 1991, pages 87- 104.
- (11)Proceedings: 1986 Fuel Supply Seminar, Electric Power Research Institute, Palo Alto, CA., EPRI Project 2369-10, Sept. 1987, pages 5-10.
- (12)Natural Gas 1994 - Issues and Trends, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0560(94), pages 8-9.
- (13)Inventory of Power Plants in the United States 1992, Energy Information Administration, U.S. Department of Energy, Washington, DC, DOE/EIA-0095(92).
- (14)Philo, Gary R.; Keefe, Daniel, E; South, David W. and Bailey, Koby A.: Outlook for the Illinois Coal Industry, Dec. 1995, Illinois Coal Development Board, Illinois Department of Commerce and Community Affairs and Argonne National Laboratory, Table 2, page 11.

Table 1: Coal Prices at Mine and Productivity

| | Mine price (\$/t) | Productivity in 1995 (t/person/day) | Annual productivity change 1985-95 (%) |
|----------|-------------------|-------------------------------------|--|
| Illinois | 23.05 | 3.87 | 5.6 |
| Indiana | 21.71 | 4.68 | 3.7 |
| Kentucky | | | |
| East | 26.00 | 3.47 | 4.6 |
| West | 20.75 | 3.97 | 3.4 |
| Colorado | 19.26 | 6.14 | 5.3 |
| Montana | 9.62 | 21.06 | 2.0 |
| Wyoming | 6.58 | 30.06 | 7.5 |

Source: DOE/EIA-0584(95) Coal Industry Annual 1995, Oct.1996, Table 48, Page 74 and Table 80, Page 154.



COALBED AND COAL MINE METHANE IN THE ILLINOIS BASIN: OCCURRENCE, COMPOSITION, ORIGIN, AND CURRENT ACTIVITIES

Heinz H. Damberger and Ilham Demir
Illinois State Geological Survey, 615 E. Peabody Drive, Champaign, IL 61820

Keywords: coalbed methane, coal mine gas, Illinois basin

BACKGROUND

Coalbed methane generally refers to methane and other gaseous hydrocarbons associated with coal, methane being the dominant one. Other gases, in particular carbon dioxide and nitrogen, are commonly associated with the hydrocarbons in variable proportions. The gases, which are by-products of the maturation process of coal, as it became buried and exposed to elevated temperatures during geologic time^[1], are stored primarily in the form of a mono-molecular layer adsorbed to the very large internal surface area of the coal. During the early stages of coal maturation, in the sub-bituminous and high volatile bituminous coal stages, water and carbon dioxide are the main by-products, with methane gradually becoming more important. In medium volatile bituminous and higher rank coals, methane becomes the dominant by-product of coal maturation.

During mining, coalbed methane is released as coal is broken up into small particles, dramatically shortening pathways to the surface, and as ambient gas pressure is reduced to about 1 atm. Also, each cut during mining exposes new coal at the face and enhances degassing. Since mixtures of 5-15% methane in air are explosive, mining regulations have long required the dilution of methane with sufficient fresh ventilation air (generally to <1% methane content) to prevent the formation of explosive mixtures. The venting of large quantities of methane into the atmosphere during and after mining has recently become a major concern because methane is a potent greenhouse gas (each gram of methane is equivalent to the impact of 21 grams of carbon dioxide, over a 100 year period^[2]). US EPA estimates that each year active coal mines in the U.S. vent about $5 \cdot 10^9$ m³ methane into the air^[2].

Efforts by the coal mining industry to recover at least a portion of this coalbed methane have resulted in the sale of about $1 \cdot 10^9$ m³ methane by 1995^[2], in states with gas-rich coals such as Alabama, Colorado, Pennsylvania, Virginia, and West Virginia. No significant recovery of coalbed methane during mining has taken place yet in the Illinois basin, primarily because of the relatively low methane concentrations in the basin's coal beds.

METHANE IN ILLINOIS BASIN COALS

Even though the methane content of coals in the Illinois basin is small in comparison to such gas-rich coal fields as the Black Warrior in Alabama, or the San Juan in New Mexico and Colorado, the total methane resources in the basin are huge ($>600 \cdot 10^9$ m³)^[3], because of the huge coal resources. Several factors cause a rather uneven distribution of coalbed methane concentration within the basin. Coal rank increases systematically from lowest rank high volatile C bituminous in the northwest part of the basin to highest rank high volatile A bituminous in the southeast^[4]. Everything else being equal, coalbed methane contents in lower rank coals are much smaller than in higher rank ones. Another important factor is depth. The coalbed methane content of coal tends to increase with depth, due primarily to increasing gas pressure which increases the amount of gas adsorbed to coal. The simultaneous increase in temperatures with depth tends to work somewhat against this trend. Because regional dips of coal beds in the basin are commonly only around two meters per kilometer, large portions of the major coal seams lie at shallow depths (about half at depths <160 meters), and even in the deepest part of the basin only small parts of the major coals occur at depths in excess of 400 meters. In other coal basins, the greatest methane contents generally are associated with coals that lie at depths >700 meters^[5].

Table 1 lists all published methane content results as determined by desorption tests of coal samples taken from drill holes. The average methane content of 1.9 ± 0.8 (std.dev.) cm³/g probably understates the methane content of in-situ Illinois basin coals. Likely reasons for the underestimate (see also footnote of Table 1) are: (1) the amount of gas lost before the coal sample could be sealed in a gas-tight container to make observations on gas desorption was underestimated; (2) the gas contents were not standardized to clean coal because the petrologic composition of the coal was not determined; (3) the gas contents were not standardized to in-situ p-T conditions; (4) the sample set is biased towards coals that tend to have smaller than average methane content because of either low rank or shallow depth, or both. In the past few years several operators have been testing coals in the southern portion of the basin for coalbed methane. They claim to have found significantly greater methane contents than have been reported in the literature; however, so far their specific data have been kept confidential. Because of their relatively low rank and shallow depth, the in-situ methane content of Illinois basin coals probably is generally well below 5-6 cm³/g; more data are needed to

properly account for the factors listed above.

Relatively little information is available on the chemical and isotopic composition of gas associated with in-situ coal in the Illinois basin. Tables 2 and 3 summarize available published and some unpublished data. The chemical data were not all reported on the same basis; for instance some probably include air trapped in the desorption canister when the coal sample was sealed in the container, as suggested by the presence of O₂ and N₂. Generally, methane represents the bulk of hydrocarbons. The amount of other gases varies significantly depending perhaps primarily on local geologic conditions and the sampling method. The few carbon isotopic analyses of methane associated with Illinois coals that have been published show δC^{13} values between -52 and -63‰, surprisingly light, certainly for thermogenic methane (Table 3). The possibility of fractionation due to migration from other sources, and also an at least partial biogenic origin must be contemplated.

COAL MINE METHANE IN ILLINOIS

It has long been known that the large voids left behind after room-and-pillar mining are an ideal place for methane to accumulate. In Illinois methane has been extracted from abandoned coal mines for many years, primarily in the southern portion of the basin, both by coal companies and by operators specializing in this technology. In recent years interest in recovering this gas has increased greatly. The amount of gas that can be extracted from abandoned mine workings is limited, though; its pressure is only about 1 atm, and the quality of the gas is variable, primarily because mine workings tend to be connected to the surface through drill holes and shafts that are not tightly sealed. When a shaft is sealed at the time of mine abandonment regulations require that vents be installed in the seal to prevent potentially dangerous buildup of gas pressure and to permit the mine to "breathe", as high and low pressure weather systems move through the area. When a high pressure system passes through, air is pushed into the mine through such vents, and any other openings, causing dilution by air of the mine gas (mostly methane). When a low pressure system follows, gas is then emitted through the vents. Coal mine methane has been used in the Illinois basin for such local applications as heating water for wash houses at mines, heating buildings and green houses, and running motors that drive electric generators, or other equipment. The chemical composition of gas samples taken from mine vents (Table 4) indicates variable admixtures of air to the usually large methane content of gas released by coal.

Active underground mines release considerable amounts of methane into the air²¹. Most is diluted in the ventilation air that is circulated through the mine to provide fresh air to the workers and to dilute any methane liberated from mined coal, from the coal left in pillars and around the perimeter of the mine, and from other coals and oil and gas pools below the mine. Values between 3,000 and 252,000 m³ CH₄/day have been reported for mines in the Illinois basin (Table 5); the average is 50,000 \pm 56,000 m³ (std. dev.) CH₄/day. The specific emission values range between <1 and 35 m³ CH₄ per metric ton of produced coal, and the average is 8 ± 7 m³/ton. Since these values are significantly above the methane content of in-situ coal, considerable amounts of methane apparently come from sources other than from the mined coal, anywhere from a few to over ninety percent, depending on the local geologic conditions.

ACKNOWLEDGEMENTS

Most the gas samples from abandoned coal mines were collected by Wayne Meents of the ISGS Oil and Gas Section between 1954 and 1982 and analyzed by chemists in the ISGS Analytical Chemistry Laboratory. Dennis Coleman was in charge of the ISGS Isotope Geochemistry Laboratory when most of the carbon isotope analyses on coalbed and coal mine methane samples were performed.

REFERENCES

1. Clayton J. L. (1998) Geochemistry of coalbed gas - A review. *International Journal of Coal Geology*, vol. 35, p. 159-173.
2. US EPA Atmospheric Pollution Prevention Division (1997) Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines. United States Environmental Protection Agency, EPA 430-R-97-020
3. Archer P. L. and Kirr J. N. (1984) Pennsylvanian geology, coal, and coalbed methane resources of the Illinois - Illinois, Indiana, and Kentucky. In Rightmire, C. T., Eddy, G.E. and Kirr, J. N., Coalbed Methane Resources of the United States. AAPG Studies in Geology #17, p.105-134.
4. Damberger, H. H. (1971) Coalification pattern of the Illinois Basin. *Econ. Geol.*, v.66, p. 488-494.
5. Scott A. R. (1997) Exploration Strategies Based on a Coalbed Methane Producibility Model. Manual for Unconventional Gas Workshop sponsored by Petroleum Technology Transfer Council, December 5, 1997, Grayville, Illinois, 238 p.
6. Harper D. (1991) Coalbed Methane in Indiana. Indiana Geological Survey Occasional Paper 56, 18 p.

7. Popp J. T., Coleman D. D., and Keogh R. A. (1979) Investigation of the Gas Content of Coal Seams in the Vicinity of Charleston, Illinois. Illinois Institute of Natural Resources Doc. No. 79/38 and Illinois State Geological Survey Open File Series 1979-2, 36 p.
8. Meents W. F. (1981) Analyses of Natural Gas in Illinois. Illinois State Geological Survey Illinois Petroleum 122, 64 p.

Table 1. Coalbed methane content of coals in the Illinois Basin, as determined by desorption tests^{1,6,7}

| State | County | Drill hole | Analyzed or reported by | Coal seam | Depth (m) | Coal thickness (m) | Lost gas (cm ³ /g) | Desorbed gas (cm ³ /g) | Residual gas (cm ³ /g) | Total gas (cm ³ /g) |
|-------|-----------|------------|-------------------------|----------------------|-----------|--------------------|-------------------------------|-----------------------------------|-----------------------------------|--------------------------------|
| IL | Clay | n. a. | TRW | Briar Hill | 328 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Clay | n. a. | TRW | Danville | 303 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Clay | n. a. | TRW | Herrin | 316 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Clay | n. a. | TRW | Seelyville | 412 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Clay | n. a. | TRW | Springfield | 332 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Coles | Charleston | IL Geol. Surv. | Danville | 294 | 0.8 | 0.03 | 1.98 | 0.70 | 2.71 |
| IL | Coles | Charleston | IL Geol. Surv. | Herrin | 325 | 0.8 | 0.05 | 0.94 | 0.52 | 1.47 |
| IL | Coles | Charleston | IL Geol. Surv. | Shelbyville | 154 | 0.6 | 0.02 | 0.12 | 0.09 | 0.25 |
| IL | Coles | Charleston | IL Geol. Surv. | Springfield | 333 | 0.4 | 0.00 | 0.33 | 1.10 | 1.43 |
| IL | Coles | Charleston | IL Geol. Surv. | Springfield | 333 | 1.0 | 0.05 | 1.36 | 0.83 | 2.22 |
| IL | Franklin | n. a. | USSteel | Herrin | 183 | n. a. | n. a. | n. a. | n. a. | 1.95 |
| IL | Franklin | n. a. | USSteel | Springfield | 204 | n. a. | n. a. | n. a. | n. a. | 1.67 |
| IL | Jefferson | n. a. | USBM | Herrin | 223 | n. a. | n. a. | n. a. | n. a. | 1.90 |
| IL | Jefferson | n. a. | USBM | Springfield | 242 | n. a. | n. a. | n. a. | n. a. | 1.00 |
| IL | Peoria | n. a. | Northern IL Gas | Colchester | 40 | n. a. | n. a. | n. a. | n. a. | 1.02 |
| IL | Wayne | n. a. | USBM | Herrin | 275 | n. a. | n. a. | n. a. | n. a. | 1.90 |
| IL | Wayne | n. a. | USBM | Herrin | 296 | n. a. | n. a. | n. a. | n. a. | 3.40 |
| IL | Wayne | n. a. | USBM | Springfield | 308 | n. a. | n. a. | n. a. | n. a. | 3.10 |
| IL | Wayne | n. a. | USBM | Springfield | 326 | n. a. | n. a. | n. a. | n. a. | 2.70 |
| IN | Gibson | BP 64 | IN Geol. Surv. | Springfield | 182 | 1.9 | 0.09 | 2.28 | 0.16 | 2.53 |
| IN | Gibson | BP 59 | IN Geol. Surv. | Springfield | 191 | 1.9 | 0.05 | 2.00 | 0.31 | 2.38 |
| IN | Knox | SDH 267 | IN Geol. Surv. | Bucktown | 159 | 0.6 | 0.13 | 1.72 | n. a. | 1.84 ¹ |
| IN | Knox | SDH 266 | IN Geol. Surv. | Coal in Staunton Fm. | 230 | 1.1 | 0.00 | 0.22 | n. a. | 0.22 ¹ |
| IN | Knox | SDH 259 | IN Geol. Surv. | Danville | 103 | 1.1 | 0.09 | 1.59 | n. a. | 1.69 ¹ |
| IN | Knox | SDH 267 | IN Geol. Surv. | Danville | 126 | 1.1 | 0.13 | 2.06 | n. a. | 2.19 ¹ |
| IN | Knox | SDH 285 | IN Geol. Surv. | Danville | 156 | 1.1 | 0.06 | 1.88 | n. a. | 1.94 ¹ |
| IN | Knox | SDH 259 | IN Geol. Surv. | Hymara | 110 | 0.5 | 0.16 | 2.88 | n. a. | 3.03 ¹ |
| IN | Knox | SDH 267 | IN Geol. Surv. | Hymara | 134 | 1.6 | 0.16 | 2.00 | n. a. | 2.16 ¹ |
| IN | Knox | SDH 266 | IN Geol. Surv. | Seelyville | 200 | 1.1 | 0.03 | 0.38 | n. a. | 0.41 ¹ |
| IN | Knox | SDH 267 | IN Geol. Surv. | Seelyville | 233 | 0.9 | 0.06 | 1.16 | n. a. | 1.22 ¹ |
| IN | Knox | SDH 267 | IN Geol. Surv. | Springfield | 163 | 1.1 | 0.16 | 2.34 | n. a. | 2.50 ¹ |
| IN | Knox | SDH 267 | IN Geol. Surv. | Survant | 211 | 0.8 | 0.25 | 2.56 | n. a. | 2.81 ¹ |
| IN | Posey | SDH 300 | IN Geol. Surv. | Coal in Dugger Fm. | 73 | 0.8 | 0.00 | 1.78 | 0.31 | 2.09 |
| IN | Posey | SDH 300 | IN Geol. Surv. | Danville | 44 | 0.9 | 0.00 | 0.72 | 0.19 | 0.91 |
| IN | Posey | SDH 301 | IN Geol. Surv. | Danville | 142 | 0.7 | 0.03 | 1.00 | 0.09 | 1.13 |
| IN | Posey | SDH 343 | IN Geol. Surv. | Danville | 143 | 0.9 | 0.00 | 1.38 | 0.13 | 1.50 |
| IN | Posey | SDH 302 | IN Geol. Surv. | Danville | 154 | 0.9 | 0.06 | 1.91 | 0.19 | 2.16 ¹ |
| IN | Posey | SDH 343 | IN Geol. Surv. | Herrin | 155 | 0.9 | 0.06 | 1.16 | 0.00 | 1.19 |
| IN | Posey | SDH 301 | IN Geol. Surv. | Herrin | 158 | 1.1 | 0.00 | 0.03 | 0.50 | 0.53 ¹ |
| IN | Posey | SDH 302 | IN Geol. Surv. | Herrin | 171 | 1.5 | 0.06 | 2.41 | 0.19 | 2.66 |
| IN | Posey | SDH 285 | IN Geol. Surv. | Herrin | 176 | 1.4 | 0.13 | 1.63 | 0.00 | 1.75 ¹ |
| IN | Posey | SDH 301 | IN Geol. Surv. | Houchin Creek | 222 | 0.5 | 0.03 | 1.38 | 0.41 | 1.81 |
| IN | Posey | SDH 302 | IN Geol. Surv. | Houchin Creek | 235 | 0.7 | 0.03 | 1.75 | 0.50 | 2.28 |
| IN | Posey | SDH 300 | IN Geol. Surv. | Hymara | 54 | 1.0 | 0.00 | 1.09 | 0.19 | 1.28 |
| IN | Posey | SDH 300 | IN Geol. Surv. | Seelyville | 131 | 1.0 | 0.00 | 2.19 | 0.31 | 2.50 |
| IN | Posey | SDH 301 | IN Geol. Surv. | Seelyville | 268 | 0.5 | 0.00 | 0.31 | 0.50 | 0.81 ¹ |
| IN | Posey | SDH 301 | IN Geol. Surv. | Seelyville | 272 | 1.5 | 0.13 | 2.13 | 0.41 | 2.66 |
| IN | Posey | SDH 302 | IN Geol. Surv. | Seelyville | 284 | 3.5 | 0.09 | 2.69 | 0.50 | 3.28 |
| IN | Posey | SDH 302 | IN Geol. Surv. | Seelyville | 285 | 3.5 | 0.16 | 3.38 | 0.91 | 4.44 |
| IN | Posey | SDH 285 | IN Geol. Surv. | Seelyville | 287 | 1.8 | 0.13 | 1.22 | n. a. | 1.34 ¹ |
| IN | Posey | SDH 300 | IN Geol. Surv. | Springfield | 80 | 1.5 | 0.00 | 2.09 | 0.31 | 2.41 |
| IN | Posey | SDH 301 | IN Geol. Surv. | Springfield | 188 | 1.1 | 0.06 | 0.31 | 0.41 | 0.78 ¹ |
| IN | Posey | SDH 285 | IN Geol. Surv. | Springfield | 202 | 1.2 | 0.16 | 2.53 | n. a. | 2.69 ¹ |
| IN | Posey | SDH 302 | IN Geol. Surv. | Springfield | 203 | 1.2 | 0.00 | 1.06 | 0.31 | 1.38 ¹ |
| IN | Posey | SDH 303 | IN Geol. Surv. | Springfield | 203 | 1.3 | 0.13 | 2.09 | 0.41 | 2.63 |
| IN | Posey | SDH 303 | IN Geol. Surv. | Springfield | 204 | 1.3 | 0.16 | 2.00 | 0.19 | 2.38 |
| IN | Posey | SDH 343 | IN Geol. Surv. | Survant | 184 | 1.1 | 0.06 | 1.75 | 0.50 | 2.31 |
| IN | Posey | SDH 301 | IN Geol. Surv. | Survant | 240 | 0.4 | 0.06 | 1.44 | 0.50 | 2.00 ¹ |
| IN | Posey | SDH 302 | IN Geol. Surv. | Survant | 252 | 0.8 | 0.09 | 2.72 | 0.41 | 3.22 ¹ |
| IN | Sullivan | SDH 344 | IN Geol. Surv. | Houchin Creek | 177 | 0.7 | 0.06 | 1.44 | 0.13 | 1.63 |
| IN | Sullivan | SDH 344 | IN Geol. Surv. | Seelyville | 272 | 1.2 | 0.03 | 2.31 | 0.25 | 2.59 |
| IN | Sullivan | SDH 344 | IN Geol. Surv. | Seelyville | 230 | 1.1 | 0.03 | 2.06 | 0.34 | 2.44 |
| IN | Sullivan | SDH 266 | IN Geol. Surv. | Springfield | 128 | 1.1 | 0.06 | 2.69 | n. a. | 2.75 ¹ |
| IN | Sullivan | SDH 344 | IN Geol. Surv. | Survant | 189 | 0.5 | 0.13 | 1.03 | 0.44 | 1.59 |

¹ Value may be low because of leakage from canister, and/or because measurement of lost gas or residual gas were not made.

n. a. = not available or not analyzed.

Table 2. Chemical composition of gas associated with in-situ coal in the Illinois Basin (Popp et al.^[7] and ISGS database). Illinois samples are from Charleston drill hole and Indiana samples are from SDH302 drill hole.

| State | County | Coal seam | Thick- ness | | Type of gas | CO ₂ | O ₂ | N ₂ | CH ₄ | C ₂ H ₆ | C ₃ H ₈ | C ₄ H ₁₀ | Btu/ft ³ (gross) |
|-------|--------|----------------|----------------|------|--------------|-----------------|----------------|----------------|-----------------|-------------------------------|-------------------------------|--------------------------------|--------------------------------|
| | | | Depth (m) | (m) | | | | | | | | | |
| IL | Coles | Shelbyville | 154 | 0.58 | Released gas | 17.0 | - | 25.0 | 54.0 | 3.0 | 1.0 | 0.0 | 930 |
| IL | Coles | Danville | 294 | 0.79 | Released gas | 1.9 | - | 15.1 | 80.2 | 2.2 | 0.5 | 0.1 | 867 |
| IL | Coles | Danville | 294 | 0.79 | Residual gas | 3.1 | - | 13.9 | 73.5 | 6.6 | 2.5 | 0.4 | 940 |
| IL | Coles | Danville | 294 | 0.79 | Total gas | 2.2 | - | 14.8 | 78.5 | 3.3 | 1.0 | 0.2 | 886 |
| IL | Coles | Herrin | 325 | 0.76 | Released gas | 3.7 | - | 0.0 | 88.9 | 4.6 | 2.4 | 0.4 | 1061 |
| IL | Coles | Herrin | 325 | 0.76 | Residual gas | 5.5 | - | 16.6 | 48.8 | 15.9 | 11.1 | 2.1 | 1440 |
| IL | Coles | Herrin | 325 | 0.76 | Total gas | 4.5 | - | 7.7 | 70.4 | 9.8 | 6.4 | 1.2 | 1240 |
| IL | Coles | U. Springfield | 333 | 0.37 | Released gas | 6.1 | - | 35.7 | 53.9 | 2.6 | 1.3 | 0.4 | 640 |
| IL | Coles | U. Springfield | 333 | 0.37 | Residual gas | 3.2 | - | 15.3 | 66.3 | 8.9 | 5.4 | 0.9 | 1001 |
| IL | Coles | U. Springfield | 333 | 0.37 | Total gas | 3.9 | - | 20.0 | 63.4 | 7.4 | 4.5 | 0.8 | 918 |
| IL | Coles | L. Springfield | 333 | 0.98 | Released gas | 1.4 | - | 21.1 | 70.4 | 4.5 | 2.2 | 0.4 | 862 |
| IL | Coles | L. Springfield | 333 | 0.98 | Residual gas | 2.5 | - | 16.2 | 63.2 | 10.7 | 6.1 | 1.3 | 1032 |
| IL | Coles | L. Springfield | 333 | 0.98 | Total gas | 1.8 | - | 19.3 | 67.8 | 6.8 | 3.6 | 0.7 | 926 |
| IN | Posey | Seelyville | 284 | 3.51 | Released gas | 1.3 | 3.7 | 37.0 | 58.0 | 0.02 | 2ppm | 0.0 | 527 |
| IN | Posey | Seelyville | 284 | 3.51 | Released gas | 1.1 | 1.7 | 33.0 | 65.0 | 0.02 | 2ppm | 0.0 | 588 |

Table 3. Carbon isotopic composition of coalbed methane in some Illinois coals (Popp et al.^[7] and ISGS database) and of coal mine methane from abandoned coal mines in Illinois (ISGS data base)

| Lab No. | County | Drill hole or Coal Co. | Mine name and Mine Index # | Coal seam | Depth (m) | Thick- ness (m) | Type of gas | Number of samples analyzed | δC^{13} CH ₄ (‰/‰) |
|---------|------------|--|--|----------------|-----------|--------------------|------------------|----------------------------|--|
| | | | | | | | | | |
| - | Coles | Charleston drill hole | - | Danville | 294 | 0.8 | released | 9 | -62.9 to -61.4 |
| - | Coles | Charleston drill hole | - | Danville | 294 | 0.8 | residual | 1 | -59.8 |
| - | Coles | Charleston drill hole | - | Herrin | 325 | 0.8 | released | 4 | -57.4 to -55.1 |
| - | Coles | Charleston drill hole | - | Herrin | 325 | 0.8 | residual | 1 | -52.1 |
| - | Coles | Charleston drill hole | - | U. Springfield | 333 | 0.4 | released | 3 | -57.1 to -56.5 |
| - | Coles | Charleston drill hole | - | U. Springfield | 333 | 0.4 | residual | 1 | -55.4 |
| - | Coles | Charleston drill hole | - | L. Springfield | 333 | 1.0 | released | 7 | -57.3 to -56.6 |
| - | Coles | Charleston drill hole | - | L. Springfield | 333 | 1.0 | residual | 1 | -54.5 |
| 3549 | Christian | Joe Simkins #1 | Peabody # 7 Mine | Herrin | 106 | | mine gas | 1 | -67.7 |
| 3540 | Clinton | Kincaid Pessina #1 Kampwerth | MI# 2040 Breese-Trenton Buxton Mine 3, MI# 85 | Herrin | 132 | 2.4 | mine gas | 1 | -65.1 |
| 3801 | Gallatin | Peabody CC | Eagle Mine #2, MI# 898 | Springfield | 76 | 1.7 | seepage at fault | 1 | -61.6 |
| 3888 | Montgomery | Gerald Stieren | Crown Mine #1, MI# 707 | Herrin | 108 | 2.1 | mine gas | 1 | -69.1 |
| 3933 | Montgomery | Gerald Stieren | Crown Mine #1, MI# 707 | Herrin | 108 | 2.1 | mine gas | 1 | -69.4 |
| 3583 | Montgomery | Freeman United MC | Crown Mine #1, MI# 707 | Herrin | 108 | 2.1 | mine gas | 1 | -69.6 |
| 3578 | Saline | Albert Farris | Dering Mine #2, MI# 125 | Springfield | 139 | 1.8 | mine gas | 1 | -62.7 |
| 3831 | Saline | Albert Farris | Dering Mine #2, MI# 125 | Springfield | 139 | 1.8 | mine gas | 1 | -60.0 |
| 3835 | Saline | Albert Farris | Dering Mine #2, MI# 125 | Springfield | 139 | 1.8 | mine gas | 1 | -62.2 |
| 3594 | Saline | Wasson Mine shaft | Wasson Mine #1, MI# 45 | Springfield | 99 | 1.6 | mine gas | 1 | -62.3 |
| 3923 | Saline | M. L. Devillez #3 | Wasson Mine #1, MI# 45 | Springfield | 110 | 1.6 | mine gas | 1 | -62.2 |
| 3216 | Saline | Cahaba #1 Willis | Peabody Eldorado Mine #20, MI# 46 | Springfield | 127 | 1.8 | mine gas | 1 | -60.7 |
| 3791 | Saline | Cahaba #1 Willis | Peabody Eldorado Mine #20, MI# 46 | Springfield | 127 | 1.8 | mine gas | 1 | -61.6 |
| 3796 | Saline | Cahaba #1 Willis | Peabody Eldorado Mine #20, MI# 46 | Springfield | 127 | 1.8 | mine gas | 1 | -61.8 |
| 3797 | Saline | Cahaba #1 Willis | Peabody Eldorado Mine #20, MI# 46 | Springfield | 127 | 1.8 | mine gas | 1 | -61.8 |
| 3832 | Saline | Cahaba #1 Willis | Peabody Eldorado Mine #20, MI# 46 | Springfield | 127 | 1.8 | mine gas | 1 | -61.5 |
| 3311 | Saline | Phillip Barrett, Schlafly #1 Morris | Dering Mine #2, MI# 125 | Springfield | 139 | 1.8 | mine gas | 1 | -63.6 |
| 3215 | Saline | Jade Oil & Gas | Dering Mine #2, MI# 125 | Springfield | 139 | 1.8 | mine gas | 1 | 62.2 |
| 3830 | Saline | Dan January | O'Gara 10 Mine, MI# 799 | Springfield | 121 | 1.7 | mine gas | 1 | -61.9 |
| 3614 | Saline | Wilson, Sutton #1P | O'Gara 8 Mine, MI# 800 | Springfield | 123 | 1.7 | mine gas | 1 | -60.9 |
| 3750 | Saline | Wilson, Sutton #1P | O'Gara 8 Mine, MI# 800 | Springfield | 123 | 1.4 | mine gas | 1 | -61.5 |
| 3834 | Saline | Wilson, Sutton #1P | O'Gara 8 Mine, MI# 800 | Springfield | 123 | 1.4 | mine gas | 1 | -60.5 |

Table 4. Chemical composition of gas collected from abandoned coal mines (Meents^[1]) and ISGS database)

| Lab No. | State | County | Mine/drill hole | %CO ₂ | %O ₂ | %N ₂ | %CH ₄ | %C ₂ H ₆ | C ₂ H ₄ | Btu/ft ³ |
|---------|-------|------------|------------------------|------------------|-----------------|-----------------|------------------|--------------------------------|-------------------------------|---------------------|
| 3539 | IL | Christian | Joe Simkins #1 | 16.3 | 1.1 | 63.1 | 19.0 | 0.45 | 0.09 | 202 |
| 3549 | IL | Christian | Joe Simkins #1 | 22.0 | 1.0 | 58.7 | 11.8 | 0.40 | 0.10 | 189 |
| 2213 | IL | Clinton | Breese-Trenton | 11.8 | 0.4 | 27.1 | 60.3 | 0.20 | 0.10 | 620 |
| 3540 | IL | Clinton | Pessina #1 | 10.2 | 0.3 | 20.7 | 68.8 | 0.00 | 0.00 | 696 |
| 2372 | IL | Franklin | Zeigler | 5.9 | 0.6 | 28.8 | 64.7 | tr | 0.00 | 655 |
| 3742 | IL | Franklin | Peabody #18 | 0.1 | 14.7 | 60.0 | 25.2 | 0.02 | 0.00 | 255 |
| 3694 | IL | Gallatin | 8 & W Coal | 0.1 | 20.7 | 79.2 | 0.0 | 0.00 | 0.00 | 0 |
| 3887 | IL | Montgomery | Gerald Stieren | 4.4 | 0.5 | 30.8 | 64.0 | 0.22 | 0.02 | 652 |
| 3888 | IL | Montgomery | Gerald Stieren | 5.0 | 0.4 | 30.0 | 64.3 | 0.22 | 0.01 | 655 |
| 3933 | IL | Montgomery | Gerald Stieren | 3.4 | 1.2 | 32.3 | 62.9 | 0.16 | 0.00 | 639 |
| 3583 | IL | Montgomery | Freeman United | 5.9 | 0.8 | 47.5 | 45.4 | 0.39 | 0.02 | 467 |
| 3689 | IL | Perry | Frank Hepp | 19.0 | 0.8 | 56.8 | 23.4 | 0.00 | 0.00 | 236 |
| 3817 | IL | Randolph | Moffat Coal #2 | 3.3 | 11.6 | 85.1 | 0.0 | 0.00 | 0.00 | 0 |
| 2371 | IL | St. Clair | Peabody Coal test | 0.3 | tr | 10.5 | 89.2 | 0.00 | 0.00 | 903 |
| 1409 | IL | Saline | A. Farris, Dering Mine | 6.7 | 1.0 | 14.4 | 77.9 | 0.00 | 0.00 | 788 |
| 1774 | IL | Saline | A. Farris, Dering Mine | 6.8 | 0.8 | 9.0 | 83.4 | 0.00 | 0.00 | 845 |
| 1918 | IL | Saline | A. Farris, Dering Mine | 6.6 | 0.2 | 4.9 | 88.3 | 0.00 | 0.00 | 894 |
| 1488 | IL | Saline | Charter Oil #1A | 0.0 | 0.6 | 12.8 | 75.9 | 9.50 | 0.00 | 960 |
| 2803 | IL | Saline | A. Farris, Dering Mine | 4.0 | 0.5 | 5.2 | 90.3 | 0.00 | 0.00 | 914 |
| 3577 | IL | Saline | A. Farris, Dering Mine | 5.0 | 0.3 | 3.7 | 91.1 | 0.00 | 0.00 | 921 |
| 3578 | IL | Saline | A. Farris, Dering Mine | 5.5 | 0.1 | 3.4 | 90.9 | 0.00 | 0.00 | 920 |
| 3831 | IL | Saline | A. Farris, Dering Mine | 5.6 | 0.2 | 2.5 | 91.7 | 0.02 | 0.00 | 928 |
| 3835 | IL | Saline | A. Farris, Dering Mine | 5.8 | 0.2 | 3.5 | 90.6 | 0.02 | 0.00 | 916 |
| 1408 | IL | Saline | Wasson Mine shaft | 7.2 | 0.3 | 48.9 | 43.6 | 0.00 | 0.00 | 441 |
| 1446 | IL | Saline | Wasson Mine shaft | 7.0 | 0.1 | 45.9 | 45.5 | 1.40 | 0.00 | 486 |
| 1910 | IL | Saline | Wasson Mine shaft | 6.2 | 0.6 | 40.7 | 51.0 | 1.50 | 0.00 | 543 |
| 3594 | IL | Saline | Wasson Mine shaft | 9.4 | 0.5 | 17.3 | 72.7 | 0.00 | 0.00 | 736 |
| 3923 | IL | Saline | Devilz | 3.3 | 4.1 | 50.8 | 41.8 | 0.01 | 0.00 | 423 |
| 3312 | IL | Saline | Phillip Barret | 2.7 | tr | 4.1 | 93.2 | 0.00 | 0.00 | 943 |
| 951 | IL | Saline | W Duncan #1 | 5.7 | 0.3 | 7.3 | 85.7 | 0.00 | 0.00 | 870 |
| 1507 | IL | Saline | Adams Unit Mine | 6.2 | 0.2 | 2.2 | 90.2 | 0.00 | 0.00 | 917 |
| 1879 | IL | Saline | Adams Unit Mine | 5.1 | 0.6 | 4.6 | 89.7 | 0.00 | 0.00 | 908 |
| 2802 | IL | Saline | Cahaba #1/Adams | 6.6 | 1.9 | 9.2 | 82.3 | 0.00 | 0.00 | 833 |
| 3216 | IL | Saline | Adams, Cahaba M. | 5.9 | 0.1 | 2.7 | 91.3 | 0.00 | 0.00 | 924 |
| 3791 | IL | Saline | Cahaba #1 Willis | 6.3 | 0.7 | 4.3 | 88.7 | 0.00 | 0.00 | 897 |
| 3796 | IL | Saline | Cahaba #1 Willis | 6.2 | 0.2 | 2.9 | 90.6 | 0.07 | 0.00 | 917 |
| 3797 | IL | Saline | Cahaba #1 Willis | 6.3 | 0.2 | 2.8 | 90.7 | 0.06 | 0.00 | 918 |
| 3832 | IL | Saline | Adams Mine | 5.9 | 0.1 | 2.9 | 91.1 | 0.05 | 0.00 | 921 |
| 3833 | IL | Saline | Adams Mine | 6.3 | 0.1 | 2.8 | 90.8 | 0.02 | 0.00 | 919 |
| 3133 | IL | Saline | Phillip Barret | 3.3 | 0.4 | 4.1 | 92.2 | 0.00 | 0.00 | 933 |
| 3311 | IL | Saline | Phillip Barret | 5.9 | tr | 2.6 | 91.5 | 0.00 | 0.00 | 926 |
| 1559 | IL | Saline | Jade Oil, Dering Mine | 7.7 | 1.4 | 5.3 | 84.3 | 0.30 | 0.00 | 862 |
| 1944 | IL | Saline | Jade Oil, Dering Mine | 6.7 | 0.2 | 5.7 | 87.4 | 0.00 | 0.00 | 884 |
| 3215 | IL | Saline | Jade Oil, Dering Mine | 6.2 | 1.5 | 8.9 | 83.4 | tr | 0.00 | 844 |
| 1656 | IL | Saline | Sahara #10 Mine | 3.9 | 14.2 | 71.7 | 10.2 | 0.00 | 0.00 | 103 |
| 1924 | IL | Saline | Sahara #10 Mine | 8.7 | 3.5 | 64.8 | 23.0 | 0.00 | 0.00 | 233 |
| 3830 | IL | Saline | Dan January | 3.1 | 0.7 | 9.8 | 86.3 | 0.02 | 0.00 | 874 |
| 3770 | IL | Saline | Ogara #8 Mine | 8.0 | 4.0 | 22.2 | 65.8 | 0.00 | 0.00 | 666 |
| 3774 | IL | Saline | Ogara #8 Mine | 10.1 | 0.7 | 11.5 | 77.7 | 0.00 | 0.00 | 785 |
| 3613 | IL | Saline | John Wilson | 6.7 | 0.1 | 3.3 | 89.9 | 0.00 | 0.00 | 909 |
| 3614 | IL | Saline | John Wilson | 7.6 | 0.0 | 2.1 | 90.3 | 0.00 | 0.00 | 913 |
| 3750 | IL | Saline | John Wilson #1P Sutton | 6.1 | 0.2 | 3.1 | 90.6 | 0.00 | 0.00 | 917 |
| 3782 | IL | Saline | John Wilson #1P | 6.4 | 0.0 | 2.9 | 90.6 | 0.00 | 0.00 | 917 |
| 3834 | IL | Saline | Wilson #1P Sutton | 5.9 | 0.1 | 2.7 | 91.3 | 0.04 | 0.00 | 924 |
| 1518 | IL | Saline | Frank Genet, Mine | 8.6 | 0.8 | 0.0 | 90.1 | 0.00 | 0.00 | 913 |
| 1973 | IL | Saline | Frank Genet, Mine | 9.1 | 0.1 | 2.1 | 88.7 | 0.00 | 0.00 | 898 |
| 1608 | IL | Saline | Sahara #1 Mine | 1.4 | 14.6 | 79.4 | 3.8 | 0.00 | 0.00 | 41 |
| 1909 | IL | Saline | Sahara #1 Mine | 7.0 | 3.7 | 72.7 | 16.6 | 0.00 | 0.00 | 168 |
| 3091 | IL | Vermilion | Bunsenville Mine | 6.5 | 14.4 | 79.1 | 0.0 | 0.00 | 0.00 | 0 |
| 3134 | IN | Sullivan | Old coal test hole | 0.6 | 0.1 | 7.0 | 92.3 | tr | 0.00 | 934 |

Table 5. Amount of methane liberated by some coal mines in the Illinois basin (US EPA^[2])

| State | County | Mine | Years averaged | Coal seam | Coal thickness (m) | Mine depth (m) | Total annual emissions, average \pm s.d. (thousand m ³ /d) | Annual coal production, average \pm s.d. (million tons) | Specific emissions, average \pm s.d. (m ³ /ton) |
|-------|-----------|--------------|----------------|---------------|--------------------|----------------|---|---|--|
| IL | Clinton | Monterey #2 | 1993/96 | Herrin | 2.3 | 101 | 10 \pm 3.7 | 2.0 \pm 0.9 | 2.0 \pm 0.7 |
| IL | Franklin | Old Ben 24 | 1993/96 | Herrin | 2.1 | 198 | 35 \pm 6 | 1.3 \pm 0.8 | 14.0 \pm 9.5 |
| IL | Franklin | Old Ben 25 | 1993/94 | Herrin | 2.1 | 183 | 34 \pm 8 | 1.4 \pm 0.1 | 8.8 \pm 1.5 |
| IL | Franklin | Old Ben 26 | 1993/96 | Herrin | 2.6 | 198 | 52 \pm 7 | 2.4 \pm 0.7 | 8.6 \pm 3.8 |
| IL | Jefferson | Orient 6 | 1993/96 | Herrin | 1.8 | 244 | 21 \pm 2 | 1.2 \pm 0.1 | 6.6 \pm 0.8 |
| IL | Jefferson | Rend Lake | 1993/96 | Herrin | 2.4 | 183 | 48 \pm 16 | 2.4 \pm 0.8 | 7.6 \pm 1.9 |
| IL | Logan | Elkhart | 1993/96 | Springfield | 1.7 | 85 | 11 \pm 2 | 1.6 \pm 0.2 | 2.7 \pm 0.7 |
| IL | Macoupin | Crown II | 1993/96 | Herrin | 2.4 | 101 | 17 \pm 2.3 | 1.5 \pm 0.1 | 3.1 \pm 2.1 |
| IL | Macoupin | Monterey #1 | 1993/96 | Herrin | 2.0 | 91 | 20 \pm 5 | 1.9 \pm 0.3 | 3.9 \pm 1.1 |
| IL | Saline | Brushy Creek | 1993/96 | Herrin | 1.8 | 76 | 21 \pm 6 | 0.8 \pm 0.4 | 10.4 \pm 4.2 |
| IL | Saline | Galatia | 1993/96 | Springfield | 2.1 | 213 | 206 \pm 56 | 4.6 \pm 1.1 | 16.5 \pm 3.5 |
| IL | Wabash | Wabash | 1993/96 | Springfield | 2.1 | 183 | 127 \pm 34 | 2.7 \pm 0.3 | 17.9 \pm 6.7 |
| IL | White | Pattiki | 1993/96 | Herrin | 1.7 | 307 | 46 \pm 12 | 1.7 \pm 0.1 | 9.9 \pm 3.1 |
| IN | Sullivan | Buck Creek | 1993/55 | Springfield | 1.5 | 91 | 12 \pm 2 | 0.5 \pm 0.2 | 10.7 \pm 4.7 |
| KY | Union | Camp No. 11 | 1993/96 | Springfield | 1.6 | 418 | 22 \pm 5 | 2.1 \pm 0.6 | 3.9 \pm 0.6 |
| KY | Webster | Baker | 1993/96 | Baker (KY 13) | 2.0 | 274 | 35 \pm 15 | 3.6 \pm 1.3 | 3.5 \pm 0.3 |
| KY | Webster | Dotiki | 1993/96 | Springfield | 1.8 | 152 | 18 \pm 1 | 2.4 \pm 0.4 | 2.6 \pm 0.2 |
| KY | Webster | Wheatcroft 9 | 1993/96 | Springfield | 2.0 | 274 | 72 \pm 46 | 1.7 \pm 1.5 | 15.0 \pm 15 |

WYOMING FOSSIL FUELS FOR THE 21ST CENTURY

Robert M. Lyman and Rodney H. De Bruin
Wyoming State Geological Survey
P.O. Box 3008
Laramie, WY 82071

KEYWORDS: Oil, Natural Gas, and Coal.

ABSTRACT

Wyoming's petroleum industry produced 1.2 trillion cubic feet of natural gas and 63.2 million barrels of oil in 1998. Over the last 10 years Wyoming's proved reserves of natural gas have risen from 10.3 to 13.6 trillion cubic feet despite production of 10.1 trillion cubic feet over the same period. Production of natural gas, including coalbed methane, is projected to reach 1.4 trillion cubic feet by 2005. Additionally, Production of natural gas liquids is projected to reach 40 million barrels and production of crude oil will be about 42 million barrels in 2005.

The Wyoming coal industry produced over 300 million short tons of coal in 1998, and production is projected to reach 365 million short tons per year by 2005. Today, 97% of Wyoming coal is used to feed coal-fired power plants in 29 states, Canada, and Spain. Future constraints on Wyoming coals, such as environmental-political policy changes and transportation availability, will provide more opportunities for coal-derived liquid fuels (LFC) and solid fuels from coal (SFC) processes.

INTRODUCTION

Wyoming is well positioned to supply fossil fuels for the United States' energy needs into the 21st century. By the year 2005, Wyoming's coal production should reach 365 million short tons (mt) (Figure 1), natural gas production should almost reach 1.4 trillion cubic feet (tcf) (Figure 2), natural gas liquids production should reach 40.0 million barrels (mmbbl) (Figure 3), and crude oil production will decline to about 42.0 mmbbl (Figure 4). For comparison, Wyoming's coal production in 1998 was 300 Mt, natural gas production was 1.2 tcf, natural gas liquids production was 36.0 mmbbl, and crude oil production was 63.2 mmbbl. Among all of the states, Wyoming is first in reserves of coal, third in reserves of natural gas, fifth in reserves of natural gas liquids, and sixth in reserves of crude oil (Table 1).

OIL, NATURAL GAS, AND NATURAL GAS LIQUIDS

The first commercial oil well in Wyoming was completed in 1884 near an oil seep. Over 1,600 oil and gas fields have been discovered in Wyoming since that time, and those fields have produced 6.5 billion bbl of oil, 23.6 tcf of gas, and over 500 mmbbl of natural gas liquids.

In Wyoming, oil and gas are produced from reservoirs of Tertiary, Cretaceous, Jurassic, Triassic, Permian, Pennsylvanian, Mississippian, Devonian, Ordovician, and Cambrian age. Commercial oil and gas production comes from every major basin and the Overthrust Belt of western Wyoming (De Bruin, 1996).

Over 75 % of Wyoming's present oil production comes from the Powder River, Bighorn, and Wind River basins (Figure 5) and is concentrated in reservoirs that are Cretaceous, Jurassic, Permian, and Pennsylvanian in age (De Bruin, 1993). The main oil reservoirs are the Cretaceous Shannon Sandstone, Sussex Sandstone, Frontier Formation, Muddy Sandstone, and Dakota Sandstone; the Jurassic/Triassic Nugget Sandstone; the Permian Phosphoria Formation; the Permian and Pennsylvanian Minnelusa Formation; and the Pennsylvanian Tensleep Sandstone (De Bruin, 1996).

Over 85 % of Wyoming's present natural gas liquids and natural gas production comes from the Overthrust Belt, Green River Basin, Great Divide Basin, and Washakie Basin (Figure 5), and is concentrated in reservoirs that are Tertiary, Cretaceous, Jurassic, and Mississippian in age (De Bruin, 1993). The main natural gas liquids and natural gas reservoirs are the Tertiary Fort Union Formation; the Cretaceous Lance Formation, Frontier Formation, Almond Formation, Muddy Sandstone, and Dakota Sandstone; the Jurassic/Triassic Nugget Sandstone; and the Mississippian Madison Limestone (De Bruin, 1996).

Wyoming's proved reserves of crude oil declined from 0.928 billion bbl in 1980 to 0.627 billion bbl in 1997. Production of crude oil during that period was 1.6 billion bbl. Proved reserves of natural gas increased from 9.100 tcf in 1980 to 13.562 tcf in 1997 despite production of 15.1 tcf over the

same period. Proved reserves of natural gas liquids increased from 0.239 billion bbl in 1980 to 0.600 billion bbl in 1997, but fluctuated more than proved reserves of crude oil or natural gas (Table 2). Production of natural gas liquids since 1980 was 431 million barrels.

Wyoming has remaining discovered and undiscovered resources of approximately 5.7 billion barrels of oil, 4.5 billion barrels of natural gas liquids, and 176.3 trillion cubic feet of natural gas (U.S. Geological Survey National Oil and Gas Resource Team, 1995). These resources are technically recoverable, but not all are economically recoverable at the present time. The oil, natural gas liquids, and natural gas resources include proved reserves, reserve growth in conventional fields, undiscovered conventional resources, and continuous-type accumulations in sandstones, shales, chalks, and coal beds. Among the states, Wyoming has 5.1 % of the remaining oil, 15.4 % of the remaining natural gas liquids, and 16.4 % of the remaining natural gas. Almost 60 % of the oil resources are located or will be discovered in the Powder River Basin. Most of the rest of the oil is located or will be found in the Bighorn and Wind River basins (Figure 5). About 96 % of Wyoming's natural gas liquids and natural gas resources are located in or will be discovered in the Overthrust Belt, the Green River Basin, the Great Divide Basin, and the Washakie Basin (Figure 5).

COAL

Wyoming's recorded coal production started in the 1860s, but until the 1970 Clean Air Act (CAA), the state's coal production remained stagnant at under 5-million short ton/year (mty). In 1969 the total production of Wyoming's coal mines was only 4.606 mt. The 1970 CAA limit on SO₂ emissions stimulated an explosion of mine development in Wyoming's Powder River Coal Field, starting in 1972 when the state's coal miners broke the 10 mty barrier. Today Wyoming mines have crossed the 300 mty milestone and are projected to reach the 365 mty mark by 2005 (Figure 1).

In 1997, 92.3% or 259.8 mt of coal produced in Wyoming came from the Wyodak coal zone (Paleocene Fort Union Formation) in the eastern Powder River Coal Field. While the mined portions of the zone consist of one to three beds of coal with an aggregate thickness between 50 and 110 feet (ft), the thickest expression is 200 ft. The delivered coal from this zone averages 0.33% sulfur, 5.12% ash, and 8,590 Btu/lb. (Glass, and Lyman, 1998).

In the Powder River Basin, coal beds occur in rock sequences deposited during either the Late Cretaceous Epoch (81 to 66.4 million years ago) or during the Paleocene or Eocene Epochs (66.4 to 36.6-million years ago) of the younger Tertiary Period. These Wyoming coals are young when compared to the 266-320 million-year-old coals that occur in the Pennsylvanian Period in the midcontinent and eastern coalfields of the U.S.

The Cretaceous peat deposits (precursors to the coal) were most often located in deltaic, coastal plain, or other nearshore settings along a Cretaceous epeiric seaway. The Tertiary coals accumulated as fresh-water peats at a time when crustal downwarping formed the basin and regional uplift caused the epeiric seaway to withdraw from the Powder River Basin area of Wyoming. Tertiary peat swamps were associated with fluvial and fluvio-lacustrine depositional systems rather than with any marine influences (Glass, 1977; Moore and Shearer, 1993).

Due to the contrasting tectonic and sedimentary settings under which Cretaceous and Tertiary coal beds formed, the Cretaceous coals are generally more laterally extensive, thinner, and higher in sulfur (> 1%) than the Tertiary coals (Glass, 1977; Moore and Shearer, 1993). These latter two differences partially explain why the Cretaceous coals are not currently mined in the Powder River Coal Field.

The remaining demonstrated strippable reserve base of the Wyodak coal bed is the largest for any single coal bed in Wyoming and perhaps for any coal bed in the U.S. This remaining reserve base is an estimated 16.5 billion short tons (bt), of which 12.7 bt is compliant coal (modified from Jones and Glass, 1992). For comparison, the strippable reserve base for the Wyodak coal bed is almost 74% of the remaining strippable reserve base in the Powder River Coal Field and 65% of the remaining strippable reserve base for Wyoming. Production and mining losses from the Wyodak coal zone through 1997 have totaled more than 3.1 bt and most of that production has occurred since 1972. Production from this coal bed was 259.8 mt in 1997.

Wyoming's remaining discovered and undiscovered resources of coal are an estimated 1,458 bt. Wood and Bour (1988) estimated that Wyoming's Powder River Coal Field contained 1.03 trillion short tons of original in-place coal resources. Of this resource, the remaining demonstrated strippable reserve base in the coalfield is an estimated 22.3 bt (modified from Jones and Glass, 1992). Of that, an estimated 13.2 bt is compliant coal, i.e., containing 0.6 or less pounds of sulfur

per million Btu. The estimate of the remaining strippable reserve base in the Powder River Basin is very conservative because it is based on an overburden cut-off of only 200-ft. The remaining strippable reserve base is likely more than double the current estimate.

LIQUIDS FROM COAL AND SOLID FUELS FROM COAL

Into the 21st century, two currently developed processes will aid in the economic utilization of Wyoming's coal resources. KFx's process to form upgraded coal (K-Fuel) from Powder River Basin coals involves a decarboxylation process. The resultant fuel is a clean, stable fuel that is essentially anhydrous. The K-Fuel has upward of 40% more heating value per pound than its feedstock coal. The LFC process, being introduced by ENCOAL, is a process which produces hotter and cleaner burning coal, oil, and gas, from low grade coal feedstock (mine waste coal). The process causes thermal fraction of coal by mild pyrolysis, and uses a controlled temperature regimen adjusted to the feed coal's properties. Reduced ash, 1/3 less NO_x and 1/2 the SO₂ emissions will help these sorts of emerging technologies come of age.

COALBED METHANE

Production of coalbed methane, derived from the Wyodak coal zone, is currently occurring just west and down dip from the coal mines on the outcrop and is increasing each year. Coalbed methane was first recognized and used in the Powder River Basin in 1916, when a rancher began using gas coming out of his water well. That well, located on a ranch near the Montana state line, apparently produced desorbed coalbed methane from a sandstone reservoir (Olive, 1957).

The first commercial venture in Wyoming that produced methane directly from a coal bed was development of the Rawhide Butte field. The wells were completed in the Wyodak coal at a depth of 400 to 500 ft. The coal bed is up to 140 ft. thick (Jones and DeBruin, 1990). The discovery of this field was directly related to surface seepage of methane gas into a housing development. Rawhide Village subdivision, located about nine miles north of Gillette and only a few miles from the Rawhide coal mine, was evacuated when methane was discovered in residents' backyards and basements as well as in the streets (Jones and others, 1987; Jones and Taucher, 1989).

In 1998, production of coalbed methane from the Wyodak coal zone in the Powder River Basin was about 56.2 million cubic feet per day or 20.5 billion cubic feet for the year (Figure 6). Production could more than triple by 2005, when the number of online wells will increase and additional pipeline capacity will be available. In regard to reserves, it is conservatively estimated that the Powder River Basin of Wyoming and Montana contains 30 tcf of recoverable coalbed methane (Ayers and Kelso, 1989).

REFERENCES CITED

- Ayers, W.B., Jr., and Kelso, B.S., 1989, Knowledge of methane potential for coalbed resources grows, but needs more study: *Oil and Gas Journal*, v. 87, no. 43, p. 64-67.
- DeBruin, R.H., 1996, Oil and gas map of Wyoming: Wyoming State Geological Survey Map Series 48, scale 1:500,000.
- De Bruin, R.H., 1993, Overview of oil and gas geology of Wyoming, in Snoke, A.W., Steidtmann, J. R., and Roberts, S. M., editors, *Geology of Wyoming: Geological Survey of Wyoming Memoir No. 5*, v.2, p. #836-873.
- Glass, G.B., 1977, Wyoming coal deposits in *Geology of Rocky Mountain coal*, a symposium: Colorado Geological Survey Resource Series 1, p. 73-84.
- Glass, G. B., and Lyman, R.M., 1998, *Geology of Wyoming's Powder River Basin coalfield: Mining Engineering*, v. 50, no. 7, p. 33-39.
- Jones, R.W., and De Bruin, R.H., 1990, Coalbed methane in Wyoming: Geological Survey of Wyoming Public Information Circular 30, 15 p.
- Jones, R.W., De Bruin, R.H., and Glass, G.B., 1987, Investigation of venting methane and hydrogen sulfide gas at Rawhide Village, Campbell County, Wyoming, in *Rawhide II Project Report, Appendix I. Geology: Wyoming Department of Environmental Quality, Cheyenne, Wyoming* (unpublished), 23 p., 12 plates.

Jones, R.W., and Glass, G.B., 1992, Demonstrated reserve base of coal in Wyoming as of January 1, 1991: Geological Survey of Wyoming Open File Report 92-4, 26 p.

Jones, R.W., and Taucher, P.J., 1989, Coal geology, geophysical logs, and lithologic descriptions from a drilling program at the Rawhide Village subdivision, Campbell County, Wyoming: Geological Survey of Wyoming Open File Report 89-2, 59 p.

Moore, T.A., and Shearer, J.C., 1993, Processes and possible analogues in the formation of Wyoming's coal deposits: Geological Survey of Wyoming Memoir 5, v. 2, p. 874-896.

Olive, W.W., 1957, The Spotted Horse coalfield, Sheridan and Campbell Counties, Wyoming: U.S. Geological Survey Bulletin 1050, 89 p.

U. S. Department of Energy, 1998, U.S. crude oil, natural gas, and natural gas liquids reserves: Advance Summary, 1997 Annual Report: Washington, D. C., 12 p.

U.S. Geological Survey National Oil and Gas Resource Team, 1995, 1995 National Assessment of United States oil and gas resources: U. S. Geological Survey Circular 1118, 20 p.

Wood, G.H., Jr., and Bour, W.V., III, 1988, Coal map of North America: U.S. Geological Survey Special Geologic Map, scale 1:5,000,000 [includes a 44 p. pamphlet].

Figure 1. Annual coal production from Wyoming (1985-1998) with forecasts to 2005 (millions of tons). Source: Wyoming State Geological Survey Coal Section.

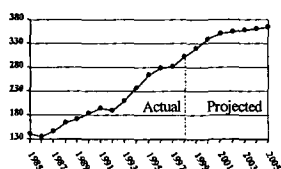


Figure 2. Annual production of Wyoming natural gas from 1980 to 1998 with forecasts to 2005 (billions of cubic feet). Source: Wyoming Oil and Gas Conservation Commission.

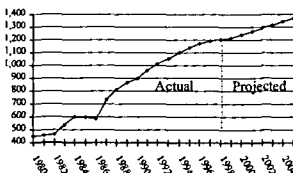


Figure 3. Annual production of Wyoming natural gas liquids from 1980 to 1998 with forecasts to 2005 (millions of barrels). Source: Wyoming Oil and Gas Conservation Commission.

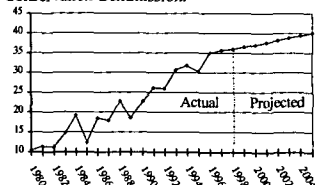


Figure 4. Annual production of Wyoming crude oil from 1980 to 1998, with forecasts to 2005 (millions of barrels). Source: Wyoming Oil and Gas Conservation Commission.

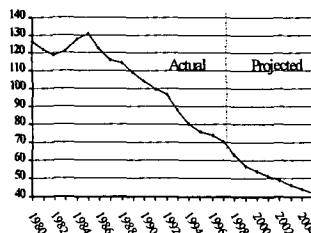


Figure 6. Annual production of Wyoming coalbed methane from 1987 to 1998, with forecasts to 2005 (billions of cubic feet). Source: Wyoming Oil & Gas Conservation Commission.

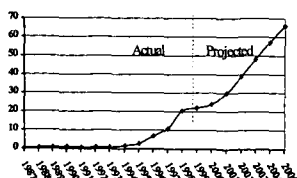


Figure 5. Index map of Wyoming basins and ranges.

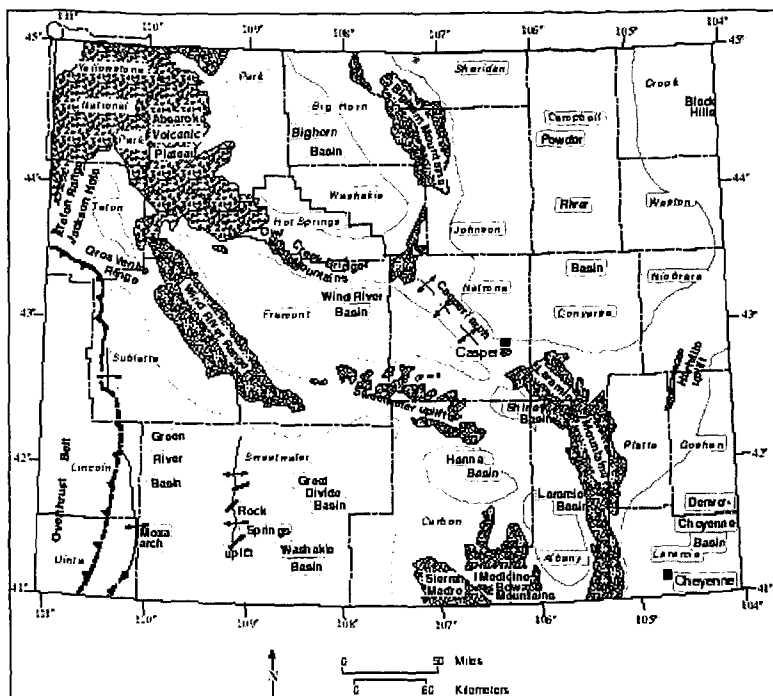


Table 1. Wyoming's ranking in proved reserves of crude oil (billions of barrels), dry natural gas (trillions of cubic feet), and natural gas liquids (billions of barrels) at the beginning of 1998.

Source: U.S. Department of Energy, 1998

| Source: U.S. Department of Energy, 1996 | | | | | |
|---|-----------|---------------|-----------------|------------|---------------------|
| State | Crude Oil | State | Dry Natural Gas | State | Natural Gas Liquids |
| Texas | 5.687 | Texas | 37.761 | Texas | 2.687 |
| Alaska | 5.161 | New Mexico | 15.514 | New Mexico | 0.869 |
| California | 3.750 | Wyoming | 13.562 | Oklahoma | 0.985 |
| New Mexico | 0.735 | Oklahoma | 13.439 | Alaska | 0.531 |
| Louisiana | 0.714 | Alaska | 10.562 | Wyoming | 0.600 |
| Wyoming | 0.627 | Louisiana | 9.673 | Louisiana | 0.437 |
| Oklahoma | 0.805 | Kansas | 8.989 | Kansas | 0.271 |
| North Dakota | 0.279 | Colorado | 8.828 | Colorado | 0.284 |
| Kansas | 0.238 | Alabama | 4.968 | Utah | 0.181 |
| Utah | 0.234 | West Virginia | 2.846 | California | 0.085 |

Table 2. Comparison of Wyoming's proved reserves of crude oil (billions of barrels), dry natural gas (trillions of cubic feet), and natural gas liquids (billions of barrels) for the years 1980 through 1997.

Source: U.S. Department of Energy, 1998.

| Year | Crude Oil | Dry Natural Gas | Natural Gas Liquids |
|------|-----------|-----------------|---------------------|
| 1980 | 0.828 | 9.100 | 0.239 |
| 1981 | 0.840 | 9.307 | 0.269 |
| 1982 | 0.856 | 9.758 | 0.477 |
| 1983 | 0.857 | 10.227 | 0.552 |
| 1984 | 0.954 | 10.482 | 0.802 |
| 1985 | 0.951 | 10.617 | 0.684 |
| 1986 | 0.849 | 9.758 | 0.955 |
| 1987 | 0.854 | 10.023 | 0.647 |
| 1988 | 0.625 | 10.308 | 0.808 |
| 1989 | 0.815 | 10.744 | 0.827 |
| 1990 | 0.794 | 9.944 | 0.568 |
| 1991 | 0.757 | 9.941 | 0.524 |
| 1992 | 0.889 | 10.826 | 0.462 |
| 1993 | 0.824 | 10.933 | 0.420 |
| 1994 | 0.565 | 10.789 | 0.395 |
| 1995 | 0.605 | 12.166 | 0.415 |
| 1996 | 0.803 | 12.320 | 0.505 |
| 1997 | 0.827 | 13.582 | 0.600 |

¹ Estimated from U.S. Department of Energy figures

NATURAL GAS IS KEY TO FOSSIL FUEL CO₂ GLOBAL WARMING MITIGATION

Meyer Steinberg
Brookhaven National Laboratory
Upton, NY 11973

Key words - CO₂ mitigation, natural gas, efficient technologies

INTRODUCTION

Fossil Fuel energy is being blamed for the impending global warming problem. The emission of the radiative gas CO₂ from a particular country is intimately connected with the size of its population, its efficiency of utilization of fossil energy and the carbon content of the fuel.¹ This paper deals with CO₂ mitigation technologies including the reuse of emitted CO₂ and indicates a direction for CO₂ emissions reduction for the U.S. economy.²

The average CO₂ emissions for the three fossil fuels are as follows: Coal - 215 LbsCO₂/MMBTU (HHV = 11,000 BTU/Lb and C content of 76%); Oil - 160 Lbs CO₂/MMBTU (HHV = 6 MMBTU/Bbl) and Gas = 115 Lb CO₂/MMBTU (HHV = 1 M BTU/cu. ft.). Table 1 shows the U.S. fossil energy consumption and CO₂ emission, the total world consumption and emission and the principal energy supply service. In the U.S., most of the coal is used for generation of electrical power, in large central power stations. Oil is mainly used for production of transportation fuel (gasoline and diesel) with some limited electrical power production and gas is mainly used for industrial and domestic heating. However, there is also lately a growing consumption of natural gas for electrical power production.

Substituting Natural Gas for Coal for Electrical Power Production

If all the current electrical power production in the U.S. is generated by natural gas in combined cycle power plants, two benefits of CO₂ emission are achieved. First, the efficiency of electrical power production is increased from the current average coal-fired plant efficiency of 34% to over 55% for a modern natural gas fired turbine combined cycle plant and secondly the CO₂ emission per unit of energy from the fuel is reduced by 47% compared to the coal-fired plant. Applying this to the U.S. consumption,³ and assuming that natural gas usage remains the same a 22% reduction in the total CO₂ emission can be realized.

Substituting Natural Gas for Oil for Automotive Transportation

Compressed natural gas (CNG) vehicles are already on the market and if natural gas is substituted for oil in the transportation sector a 13% reduction in CO₂ emissions can be realized in the U.S. Thus, the substitution of natural gas for Coal and Oil in the electrical power and transportation sectors adds up to a 35% overall reduction in CO₂ emissions.

The Carnol System for Preserving the Coal Industry for Electrical Power Production and Reducing Oil Consumption by Substituting Methanol in the Transportation Sector

The Carnol System consists of generating hydrogen by the thermal decomposition of methane and reacting the hydrogen produced with CO₂ recovered from coal-fired central power stations to produce methanol as a liquid transportation fuel.^{4,5,7,10} Figure 1 illustrates the Carnol System which has the following advantages: 1. The Carnol System preserves the coal industry for electrical power production. 2. The Carnol System produces a liquid fuel for the transportation sector which fits in well with the current liquid fuel infrastructure. 3. The Carnol System reduces consumption of the dwindling domestic supplies of fuel oil in the U.S.

In the Carnol System, the carbon from the coal is used twice, once for production of electricity and a second time for production of liquid fuel for fueling the transportation sector, in automobile vehicles. The reduction in CO₂ emissions results from two aspects. The elemental carbon produced from the thermal decomposition of the methane is not used as fuel. It is either sequestered or sold as a materials commodity. In this respect, thermal decomposition of methane (TDM) has an advantage over the conventional steam reforming of methane (SRM) for hydrogen production reduced. In the TDM process, carbon is produced as a solid which is much easier to sequester than CO₂ as a gas. Furthermore, the energy in the carbon sequestered is still available for possible future retrieval and use. The carbon can also be used as a materials commodity, for example, as a soil

conditioner. Table 2 gives the estimate of CO₂ emissions using the Carnol System applied to the U.S. 1995 consumption and indicates a 45% overall CO₂ emissions reduction. The methanol in this case is used in conventional internal combustion engines (IC) which is 30% more efficient than gasoline driven IC engines.⁶ The natural gas requirement would have to increase to 62 Quad which is three times the current consumption of natural gas for heating purposes. The rise in natural gas requirement is because only about 58% of the natural gas energy is used for hydrogen for methanol production. The carbon produced is sequestered unburned to the extent of 0.58 GT. This can be considerably reduced by adopting to fuel cell vehicles.

Carnol System with Methanol Fuel Cells for the Transportation Sector and Substituting Natural Gas with Combined Cycle Power for Coal Fired Central Station Power

In the not too distant future, fuel cells will be developed for automotive vehicles. This will improve the efficiency of automotive engines by at least 2.5 times compared to current gasoline driven internal combustion engines.⁸ Direct liquid methanol fuel cells are under development.¹¹ If we use coal or oil for central power stations, there will be too much CO₂ generated for liquid fuel methanol by the Carnol Process for use in the transportation sector with fuel cells. Therefore, it is much more energy balanced if we use natural gas for power because it generates the least amount of CO₂ per unit of energy. In this scenario, the natural gas in a combined cycle plant displaces coal for power production and displaces oil for methanol by the Carnol Process for transportation. The results are shown in Table 3. Thus, by applying natural gas for electrical power production, liquid fuels production for fuel cell driven automotive engines and for heating purposes an overall CO₂ emissions reductions of over 60% can be achieved. This degree of CO₂ emission reduction could stabilize the CO₂ concentration and prevent the doubling of the CO₂ in the atmosphere expected by the middle of the next century if business is conducted as usual. The 0.32 GT of carbon required to be sequestered is about 3 times less than the amount of coal mined in the U.S. currently. If a market can be found for this elemental carbon, such as a soil conditioner, the cost of methanol production can be significantly decreased.

Natural Gas Supply and Utilization

The all natural gas energy system of Table 3 requires a three-fold annual consumption in natural gas. Recent reports indicate that the current estimated reserve of conventional natural gas is of the same order of magnitude as the current estimated oil reserves which might last only for another 80 years or so. However, unconventional resources, especially methane hydrates⁹ and coal bedded methane indicate an enormous resource which is estimated to be more than twice as large as all the fossil fuel resources currently estimated in the earth. If this is so, then we can begin to think of utilizing natural gas for reducing CO₂ emissions in all sectors of the economy. It appears that even today, deep mined coal in several parts of the world, especially in England, Germany, and the U.S., has become too expensive; and, as a result, many of these mines have been closed. Most economical coal used today comes from surface mined coal. Furthermore, the contaminants in coal, sulfur, nitrogen and ash in addition to the high CO₂ emission mitigate against its use. Rail transportation of coal also becomes a problem compared to pipeline delivery of natural gas. When natural gas becomes available, even at a somewhat higher cost, it can displace coal and even oil for power production and transportation. Long term supply of economical natural gas is the main concern for increased utilization of natural gas.

Economics of Natural Gas Displacing Coal and Oil

The current unit cost for fossil fuel in the U.S. is roughly for coal \$1.00/MMBTU, oil \$3.00/MMBTU and for gas \$2.00/MMBTU. For the total consumption of 76 Quad in 1995, the primary fossil fuel energy bill was \$167 billion. Applying this to the all natural gas scenario of Table 3, we come up with a natural gas fuel bill for the required 49 quads of \$98 billion. So there is a resulting 41% savings in the current fossil fuel bill. The cost of natural gas could go up to \$3.50/MMBTU without the fuel bill exceeding the current fuel bill. In order to achieve these results, capital investment for the replacement of new technologies must be made. Only incremental replacement cost need be considered, since capital investment will be needed, in any case, to replace old equipment under business as usual conditions. Table 4 indicates the incremental capital replacement cost to achieve the all natural gas economy based on the following data.

- a) Replacement of coal fired plants including scrubbers, etc., runs about \$2000/kw(€); for the more efficient natural gas combined cycle plants runs about \$1000/KW(€); thus, there is a \$1000/Kw(€) capital cost savings and when applied to an installed capacity of 400,000 MW(€), the savings amounts to \$400 billion.

- b) For replacing oil refineries with new Carnol methanol plants which require CO₂ removal and recovery from the natural gas power plants, it is estimated that the current unit cost is \$100,000 per daily ton of methanol. The total incremental cost to supply the total 14 quads of methanol for fuel cell vehicles is then \$220 Billion. No credit was taken for the replacement of oil refineries, over time, so that this incremental capital cost is probably high.
- c) New pipelines and LNG tanks will have to be built to transport the natural gas and new methods of extracting natural gas eventually from deep sea wells containing methane hydrates. Assuming \$1 million per mile for these new gas supply facilities and a rough estimate of 200,000 miles needed gives a capital cost of roughly \$200 billion. It is also assumed that the liquid methanol pipeline and tanker distribution will be about equal to the current liquid gasoline distribution for the transportation sector.
- d) In terms of replacing the current existing more than 100 million gasoline driven IC engine vehicles with fuel cell vehicles, it eventually should not cost much more than the present average cost of \$15,000 to \$20,000 per vehicle. And, so the incremental cost should be negligible and may even show a savings because of the more efficient fuel cell vehicle than the IC engine vehicle.

Table 4 indicates that the incremental savings due to the new technologies in the one electrical power sector just about balances the incremental cost in the other three sectors. Thus, the new total incremental capital replacement cost, over the long run, is negligible compared to the capital cost requirement for continuing with the current business as usual current power technology structures.

Conclusions

The ability of achieving a 60% reduction in the U.S. CO₂ emissions by natural gas fuel substitution with improved technologies is based on the following assumptions and developments:

- 1. that there are vast reserves of natural gas that can be recovered from both conventional and non-conventional natural gas resources especially from methane hydrates and coal bedded methane at costs which are not more than about double current gas productions cost.
- 2. that an efficient Carnol process for methanol production based on thermal decomposition of methane can be developed.
- 3. that an efficient direct methanol fuel cell vehicle can be developed.

The benefits in terms of mitigating global warming provides a strong incentive for working on and achieving the required development goals. The all natural gas economy with efficient technologies for CO₂ global warming mitigation avoids alternatives of (1) sequestering CO₂ in the ocean or underground, (2) switching to nuclear power, and (3) relying solely on solar and biomass energy.

References

- 1. Kaya, Y., et al., "A Ground Strategy for Global Warming," paper presented at Tokyo Conference on Global Environment (September 1989).
- 2. Steinberg, M., "Natural Gas and Efficient Technologies: A Response to Global Warming," BNL 6545 I, Brookhaven National Laboratory, Upton, N.Y. 11973 (February 1998).
- 3. Carson, M.C., "Natural Gas Central to World's Future Energy Mix," Oil and Gas Journal, pp. 34-37 (August 11, 1997).
- 4. Steinberg, M., "Production of Hydrogen and Methanol from Natural Gas with Reduced CO₂ Emission," Proceedings of the 11th World Hydrogen Energy Conference (WHEC), Vol. 1, pp. 499-510, Stuttgart, Germany, (June 23-28, 1996).
- 5. Steinberg, M., "Methanol as an Agent for CO₂ mitigation," Energy Conversion 38 Supplement, pp. S423-S430 (1997).
- 6. U.S. Environmental Protection Agency, "Analyses of the Economic and Environmental Effects of Methanol as an Automotive Fuel," Research Report 0.730 (NTIS PB90-225806), Office of Mobile Sources, Ann Arbor, MI (1989).
- 7. Steinberg, M., "Natural Gas Decarbonization Technology for Mitigating Global Warming," BNL Report 65452, Brookhaven National Laboratory, Upton, NY (January 1998).

8. World Car Conference 1996, Bourns College of Engineering Center for Environmental Research and Technology, University of California, Riverside, CA (January 21-24, 1996).
9. Paul, C., "Atlantic Gas Hydrates Target of Ocean Drilling Program, Target of Ocean Drilling Program Leg," *Oil and Gas Journal*, pp. 116-118 (October 16, 1995).
10. Steinberg, M., "CO₂ Mitigation and Fuel Production," BNL Report 65454, Brookhaven National Laboratory, Upton, NY (October 1997).
11. Halput, G., et al., "Direct Methanol Liquid Fuel Cell," JPL Report, Jet Propulsion Laboratory, Pasadena, CA (May 1997).

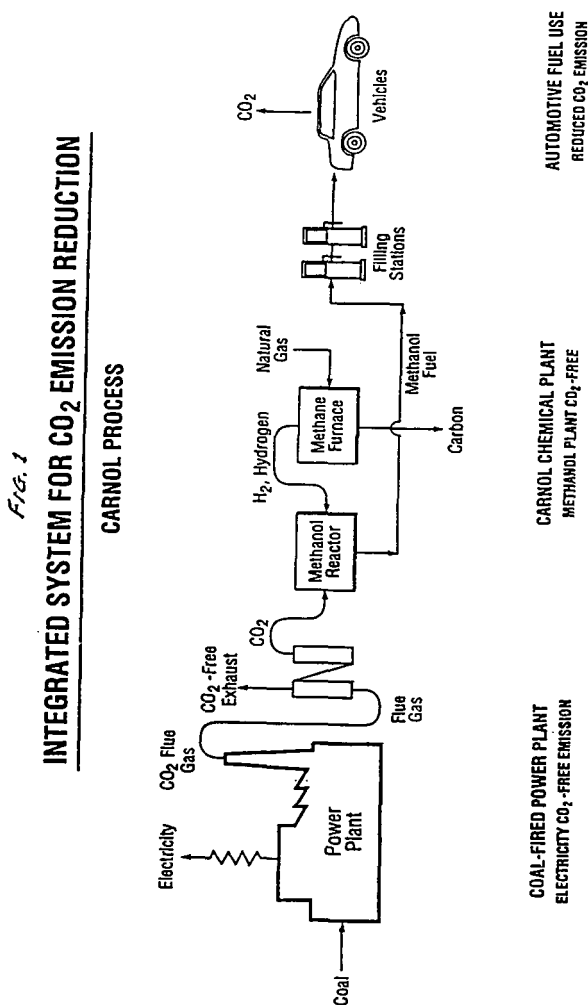


Table 1
Total Fossil Fuel Energy Consumption and CO₂ Emission for the U.S. in 1995^{b)}

| Fuel Type | Quantity | Energy Consumption Quads 10 ¹⁵ Q BTU | Principal Energy Service | CO ₂ Emission | |
|-------------|--------------------------|---|--------------------------|--------------------------|-----|
| | | | | GT(CO ₂) | % |
| Coal | 0.9x10 ⁹ tons | 20 | electricity | 2.15 | 35% |
| Oil | 5.8x10 ⁹ bbls | 35 | Auto transport | 2.80 | 45% |
| Gas | 21.0 TCF | 21 | heating | 1.21 | 20% |
| U.S. Total | | 76 | | 6.16 (1.68 GT(C)) | |
| World Total | | 330 | | 22.7 (6.2 GT(C)) | |

TCF = Trillion (10¹²) cubic feet

GT = Giga (10⁹) tons

Q = Quads (10¹⁵) BTU

Table 2
**Carnol Methanol Substitution for Oil in the Conventional Auto Transportation Sector
Produced from Natural Gas and CO₂ from Coal-fired Power Plants**

| Fuel Type | Natural Gas Consumed Quads | Energy Consumed Quads | Energy Service | CO ₂ Emissions GT(CO ₂) |
|---|-------------------------------|--------------------------|----------------|---|
| Coal ^{a)} | -- | 20 | Electricity | 0.22 |
| Methanol ^{a)} substitutes for gasoline | 41 | 24 | Auto Transport | 1.96 |
| Gas | 21 | 21 | Heating | 1.21 |
| Total | 62 | 65 | | 3.39 |
| Reduction from current CO ₂ emission | | | | 2.77 |
| % CO ₂ Emission Reduction from 1995 level | | | | 45.0% |
| Elemental carbon sequestered | | | | 0.58 GT (C) |

Table 3
**Natural Gas substituted for Coal Fired Power Production, Carnol Process for Methanol Production,
Substituting for Oil in Fuel Cell Vehicles for the Transportation Sector**

| Fuel Type | Natural Gas Consumption Quads | Energy Consumption Quads | Energy Service | CO ₂ Emission GT (CO ₂) |
|--|----------------------------------|-----------------------------|------------------------------|---|
| Natural gas for coal ^{a)} | 14 | 14 | Electricity | 0.08 |
| Methanol for oil | 24 | 14 | Auto Transport Fuel Cells | 1.12 |
| Gas | 21 | 21 | Heating | 1.21 |
| Total | 59 | 49 | | 2.41 |
| Reduction from Current CO ₂ Emissions | | | | 3.75 |
| % CO ₂ Emission Reduction from 1995 level | | | | 61% |
| Elemental carbon sequestered | | | | 0.34 GT (C) |

a) Natural gas for combined cycle power plant is 55% efficient and 90% of CO₂ emissions is recovered for Carnol plant.

Table 4
Capital Investment Required to Replace Present Power Structure

| Present Power Structure (and capacity) | Replacement Structure (and capacity) | Incremental Unit Capital Cost | Incremental Replacement Capital Cost \$10 ⁹ (\$ Billions) |
|---|---|--|--|
| Coal fired electrical ^{a)} power 400,000 MWe | Natural gas fired combined cycle electrical power | - \$1000/kw (savings) ^{a)} | - \$400 |
| Oil refineries ^{b)} 35 Quads | Carnol methanol plants 14 Quads | \$10 ⁹ /T/D Methanol ^{b)} | + \$200 |
| Wells and pipelines ^{a)} | additional pipeline and new methane hydrate wells | \$10 ⁹ /mile ^{a)} 200,000 miles of gas lines | + \$200 |
| Automotive IC vehicles 100 x 10 ⁶ | Fuel cell vehicles | 0 ^{a)} | - 0 |
| Net total incremental replacement cost | | | - 0 |

THE ROLE OF NUCLEAR POWER IN U.S. ENERGY SUPPLY

Robert T. Eynon
U. S. Department of Energy
1000 Independence Ave SW
Washington, DC 20585

KEYWORDS: nuclear power, Kyoto protocol, energy forecasts

ABSTRACT

Commercial nuclear reactors provide almost one-fifth of U. S. electricity supply. This paper describes the costs and performance of these plants and provides projections of their contribution through 2020. The economics and engineering issues that determine if plants will retire before their operating licenses expire or if plants will seek license renewal are presented. Environmental considerations that could alter outcomes are also addressed including impacts on fossil fuel consumption and carbon emissions. The projections are drawn from the Energy Information Administration reports *Annual Energy Outlook 1999* and *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*.

BACKGROUND

Nuclear power plants provided 18 percent of the electricity generated in the United States in 1997. It is the second largest contributor behind coal which provides about 53 percent. Oil and natural-gas fired plants contribute about 17 percent and renewable sources (including hydroelectric) make up the balance. However, the role of nuclear power is expected to diminish in the future as plants begin to retire and no new capacity is built. This is likely to occur even though the plants currently operating have shown remarkable improvement in operating performance over the last several years. Since 1985 the performance of nuclear plants as measured by the capacity factor¹ has improved from 58 percent to 77.4 percent in 1995 before dropping back to 70.8 percent in 1997.² These improvements reflect a coordinated industry wide effort³ to reduce incidents where plants are taken out of service (forced outages) and to increase periods between refueling outages. At the same time efforts have been made to reduce operating costs of plants to make them competitive with other generator types in response to the opening of markets for generation services to competition.

Nuclear plants have operating licenses that expire after 40 years. However, to this date no plants have actually achieved this period of service. Several plants have retired early (after operating 17 to 35 years) because of combinations of high operating costs, performance problems, and needs for significant capital investment to replace components such as steam generators.

In order to determine what role nuclear power will have in the future it is necessary to consider the remaining lives for the balance of plants currently in service⁴. To that end, it has been assumed that if it is economic to continue to operate a nuclear plant an age related investment of about \$150 per kilowatt (about \$150 million for a typical unit) will be required after 30 years of operation for plants with older designs (about one half of the existing capacity) in order to permit them to continue generating for 10 additional years.⁵ Units with newer designs are estimated to require somewhat

¹Capacity factor is the ratio of the actual electricity produced by a plant divided by the electricity that could have been produced at continuous full-power operation over the entire year.

²Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998).

³The nuclear industry formed a collaborative organization called the Institute for Nuclear Power Operations to address comprehensive improvements in the operation of nuclear generators.

⁴The Energy Information Administration produces projections of U.S. energy markets published in the *Annual Energy Outlook 1999*. The report has projections for nuclear power through 2020. See Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

⁵Plants that have already incurred capital expenditures for steam system replacements are assumed to operate for 40 years with no additional investment.

lower costs. This expenditure is intended to be equivalent to the cost that would be associated with any of several needs such as a one time investment to replace aging equipment (steam generators), a series of investments to fix age related degradation, increases in operating costs, or costs associated with decreased performance. This investment is compared with the cost of building and operating the lowest cost new plant (typically a natural gas-fired combined-cycle unit) over the same 10 year period. If the cost of the investment for the nuclear plant is less than the alternative, it is assumed to remain in service. If the alternative is less expensive, then the nuclear plant is retired after 30 years of operation. Using these assumptions results in projections of almost 24 gigawatts of nuclear capacity being retired prematurely. This is in addition to the almost 7 gigawatts of capacity that has already been retired. A substantial portion of this capacity is located in the Northeastern United States and is expected to retire between 2000 and 2006. The retired capacity in the Northeast is almost 11 percent of total capacity available in that region.

A similar method is used to determine if it is economic to apply for license renewal and operate plants for an additional 20 years. Nuclear plants are estimated to face an investment of \$250 per kilowatt (about \$250 million for a typical one gigawatt unit) after 40 years of operation to refurbish aging components. This investment is compared with the lowest cost new plant alternative evaluated over the same 20 years that the nuclear plant would operate. If the nuclear plant is the lowest cost option, it is projected to continue to operate. EIA projects that it would be economic to extend the operating licenses for six gigawatts of capacity⁶.

PROJECTIONS

Given the retirements (determined by the economic test at 30 years and by the expiration of operating licenses⁷) and license renewals discussed previously, nuclear generation is projected to decline over time. Nuclear generation is projected to drop from 629 to 359 billion kilowatt hours from 1997 to 2020 in the reference case⁸. Most of this decrease is expected to occur after 2010 when plants installed in the 1970's which don't pass the license renewal test begin to retire at the end of their operating licenses. As a result of lower output, the share of nuclear generation is expected to decline from 18 percent in 1997 to 7 percent in 2020. By 2020, renewable sources (including hydroelectric generation) account for more generation than nuclear plants. Nuclear generation drops from the second largest provider in 1997 to fourth in 2020 behind coal, natural gas, and renewable sources.

Because there is considerable uncertainty related to the investments required to allow plants to operate for 40 years, two alternative cases with higher and lower cost assumptions were analyzed. In the higher cost case the \$150 per kilowatt investment to allow a plant to continue operations after 30 years was assumed for all reactors including the newer design units. This assumption captures the possibility of plant degradation and fuel storage costs beyond those assumed in the reference case. In this case an additional 16 gigawatts are retired by 2020. The retired nuclear capacity is replaced with new coal-fired steam units (30 percent) and new natural gas-fired combined cycle units (28 percent) and combustion turbines (42 percent). The consumption of coal and natural gas are higher in 2020 by about 0.4 quadrillion Btu for each fuel or 2 and 5 percent, respectively. Because more fossil fuels are consumed, the emissions of carbon are 17 million metric tons higher than the 745.5 million metric tons in the reference case in 2020.

In the more optimistic case it was assumed that plants could operate beyond 40 years without incurring a major capital expenditure at either 30 years or 40 years. This assumption is made to determine the impacts under the most optimistic outcome. These assumptions result in higher nuclear generation which causes fossil-fired additions to decline by 28 gigawatts and renewable sources to decrease by almost 1 gigawatt compared with the reference case in 2020. Carbon emissions are 30 million metric tons less than in the reference case in 2020. This reduction represents about 15 percent of the growth in carbon emissions from electricity production between 1997 and 2020. This means that 15 percent of the increase in carbon emissions could be offset if nuclear plants continued to operate beyond 40 years.

⁶ In 1998 Baltimore Gas and Electric, owner of Calvert Cliffs, and Duke Power, owner of Oconee, applied to the Nuclear Regulatory Commission to renew the licenses for those plants.

⁷ There are currently no announcements for early retirement of plants beyond those that have already been shutdown.

⁸ Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998). The report is available at <http://www.eia.doe.gov>.

The availability of a permanent storage site for high level waste is an issue important to the future of nuclear power. The lack of a permanent storage site is a major factor in the decision to build nuclear capacity. The requirements for spent fuel disposal vary slightly for the cases described above. In addition to the 35 thousand metric tons of spent fuel already accumulated, an additional 39 to 43 thousand metric tons would be generated by 2020 for the cases analyzed, more than doubling current inventories.

Beyond the waste storage problem there are also high investment requirements for new nuclear plants that make them non-competitive with new coal-fired steam plants and natural gas-fired combined cycle units through 2020. Table 1 provides the cost information for a coal-fired steam plant, a natural gas combined-cycle unit, and a nuclear unit. The nuclear cost assumes that plants can be built at guaranteed prices⁹. The table shows that the capital portion of the cost of the nuclear plant is higher than the other technologies. Even though nuclear plants have a very low fuel cost compared with the other types, the difference is not sufficient to overcome the differences in capital costs. As a result the total cost of producing electricity from a new nuclear unit is higher than for the other generating types.

Although there are significant impediments to construction, it is useful to examine the impacts that existing nuclear power plants could have on achieving reductions in carbon emissions required in the Kyoto Protocol.¹⁰ There are a number of cases considered in this analysis that vary assumptions regarding trading of carbon permits, carbon sinks, and carbon offsets. These assumptions result in different levels of the carbon fee and cause the costs of providing electricity from fossil-fired plants to vary. As a result the economic test used to determine the operating lives of existing nuclear plants results in different levels of retirements of nuclear capacity. Figure 1 shows the levels of nuclear capacity that result. Nuclear capacity ranges from 48 to 86 gigawatts in 2020 for the reference case and three percent below 1990 case, respectively. This range is the result of the different carbon fees only as all other assumptions regarding nuclear power are unchanged.

In order to determine if new nuclear capacity could also help reduce carbon emissions, two sensitivity cases were analyzed¹¹. In one case it was assumed that carbon emission limits could be set at 9 percent above 1990 levels in 2010 if international activities including trading of carbon permits and offsets from other greenhouse gases and forestation projects are allowed. Although this case raises the costs of generating power from fossil-fired units by incorporation of a carbon fee (\$163 per ton by 2010) to the delivered price of fuel, the increases are not sufficient to overcome the difference in costs between new nuclear capacity and fossil-fueled technologies. As a result, there are no new nuclear plants built through the year 2020 in this case.

In the second sensitivity case, a more stringent target of 3 percent below 1990 levels was set for carbon emissions eliminating the carbon permits in international markets but allowing credit for sinks and offsets. For this sensitivity test it was assumed that the initial nuclear units could be constructed without the cost premium typically associated with new designs. The basis for this assumption is that vendors would be willing to build plants at a fixed price in order to be competitive with other providers and to gain a market share.

Under these assumptions, about 40 gigawatts of nuclear power are constructed, mostly between 2015 and 2020. The use of fossil fuels declines compared with a case where the same emissions

⁹It is assumed that there is no uncertainty in costs quoted before a new design is built and, if costs exceed the original estimate, they are not passed on to the plant owner. The costs used under this assumption are those that would be expected for the fifth unit constructed under reference case assumptions. The cost of the fifth unit is assumed to be that of a mature technology where uncertainties in cost estimates have been eliminated.

¹⁰ For a description of the protocol and analysis see Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

¹¹These sensitivity cases are compared with the reference case used in the Kyoto analysis. The Kyoto reference case, although similar, is not the same as the reference case used in the *Annual Energy Outlook 1999* because of differences in assumptions regarding technological improvements and costs. The differences are discussed in Energy Information Administration, *Impacts of the Kyoto Protocol on U. S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), Appendix A. The assumptions regarding the operating lives of nuclear plants are the same as those used in the *Annual Energy Outlook 1999*.

targets are assumed but without the option for new nuclear generators. Total fossil fuel consumption declines by 1 quadrillion Btu or 6 percent when new nuclear plants are built. In addition, even though consumers are projected to increase their use of electricity by one percent above the case where new nuclear power is excluded, there is a drop in the price of electricity. Average electricity prices to consumers decline by 4 mills per kilowatt hour (4 percent) compared with the case without new nuclear power. The addition of new nuclear power plants results in reductions in the cost of a carbon allowance. The price for an allowance would decline from \$245 to \$203 per metric ton of carbon (1996 dollars) in 2020¹². It is also interesting to note that slightly less existing nuclear capacity would be economic to operate in 2020 (about 2 gigawatts) because the lower cost of the carbon permit causes fossil-fired plants to be more competitive with nuclear plants.

These results indicate the potential for nuclear power in a carbon constrained environment. However, the case does not address the impacts of developing the supporting infrastructure for nuclear power that would be required to permit the rapid expansion that these results suggest. If costs associated with new infrastructure are required, then there could be less penetration of new nuclear capacity than projected in this case.

CONCLUSIONS

Nuclear power which currently provides 18 percent of electricity supply is expected to drop to 7 percent by 2020 as existing plants retire and no new plants are built. Some existing plants will retire before the end of their operating licenses due to performance problems and age related investment requirements. New plants are not expected to be built because high capital costs make them non-competitive with other technologies and because permanent storage for waste is not available. The reduced contribution of nuclear power in the future increases consumption of fossil fuels and increases carbon emissions. If aging and performance problems do not cause plants to be shutdown early, then the growth in carbon emissions between 1997 and 2020 could be reduced by 15 percent. If there are mandates to reduce carbon emissions to 3 percent below 1990 levels by 2010 and thereafter, then nuclear power plants would be economic to build starting about 2015, given that vendors offer firm prices for construction.

ACKNOWLEDGEMENTS

The author expresses appreciation for technical assistance and comments provided by Laura Church, James Hewlett, Mary Hutzler, David Schoeberlein, and Scott Sitzler.

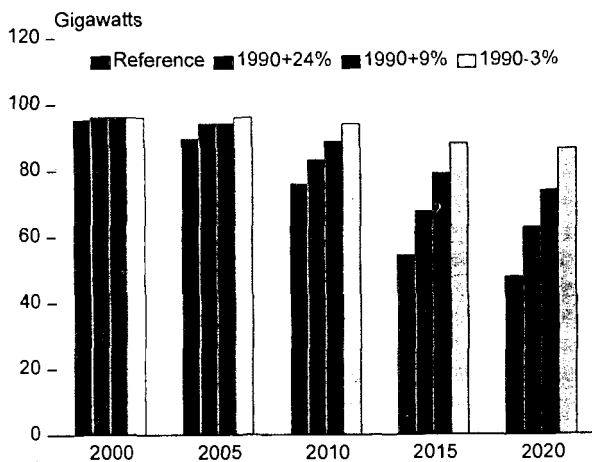
Table1 Cost of Producing Electricity from New Plants

| | Pulverized Coal | | Advanced Combined-Cycle | | Advanced Nuclear | |
|---------------|-----------------|-------|-------------------------|-------|------------------|-------|
| | 2010 | 2020 | 2010 | 2020 | 2010 | 2020 |
| 1996mills/kWh | | | | | | |
| Capital | 24.21 | 24.95 | 6.24 | 6.32 | 33.81 | 35.05 |
| Fixed O&M | 3.18 | 3.18 | 1.97 | 1.97 | 7.79 | 7.79 |
| Fuel | 10.09 | 9.55 | 22.13 | 23.54 | 3.74 | 3.86 |
| Total | 37.48 | 37.67 | 30.34 | 31.83 | 45.34 | 46.70 |

Note: Costs calculated on 80 percent capacity factor; Variable O&M included in fuel component. The cost for the advanced nuclear unit is for a mature technology which is assumed to occur when the fifth unit is constructed.

¹²Although it is assumed that carbon reduction targets must be met by 2010, there are no nuclear units constructed by then and there is no change in the carbon permit price.

Figure 1 Projections of Nuclear Capacity, 2000-2020



Future Sources of Heavy Crude and their Production and Upgrading Technology

Teh Fu Yen
School of Engineering
University of Southern California
Los Angeles, CA 90089-2531

KEY WORDS: nanotechnology, asphaltene, bitumen

ABSTRACT

Worldwide premium-quality lighter crude has been depleting during the last two decades. Future demands for petroleum is centered on the use of heavy and extra-heavy oil, which is difficult to produce, transport and refine. An assessment is made on the types and sources of heavy crude as feedstocks for the conventional upgrading technology, including the requirements for stringent environmental regulations. A strategy for future production (the up-stream) and upgrading (the down-stream) will be presented. Horizontal drilling, the use of microorganisms and a number of physical methods, such as ultrasound, median microwave, cold plasma, electrokinetic and monocrystalline intermetallics, etc., will be discussed for the first time.

INTRODUCTION

U.S. DOE¹ has assessed that for the world crude oil supply from 1900 to 2100, extra heavy crude and bitumen will be used as a significant portion of the total consumption (40 Mbbl/ day), near the year 2060. At present, engineers have developed a myriad of processes to convert fossil fuel residues to lighter liquids. For example, both thermal cracking and hydrotreating (hydrocracking) have been commercialized worldwide. Certain designs of a given process usually depend on the properties of the feed. In order to adopt a given unit for a variety of other feed streams, the particular process must be modified from the original tailor-made system developed and intended for a given source or type. Without exception, all existing and frequently used processes, e.g., the H-oil and LC fining, suffer from this shortcoming.

Typical heavy oils produced at different geographical locations are quite different in properties. In this analysis, the common heavy oil sources used by the traditional processes are listed. After most of these sources are depleted, other massive sources of heavy oil or bitumens will be explored for commercial uses. Also, future potential sources of extra-heavy oil and bitumens are evaluated. The current technology of the refining process is based on the following principles: carbon fragmentation, carbon rejection, hydrogen addition and carbon rearrangement.

In this manner, asphaltene becomes pivotal, for example, in the processes of deasphaltene, asphaltene cracking, asphaltic interconversion, hydrogenation, hydrogenolysis of the aromatics and heterocyclics². Usually, the mass distribution of the four asphaltic fractions—asphaltene, resin, aromatics and saturates (SARA)—is the primary factor that determines the characteristics of a given heavy oil. For heavy oil or bitumens from tar sands, the asphaltic fractions (nonvolatile) are the major constituents. For naturally occurring asphalt and solid bitumens, the asphaltene content of both may reach 90%+. There is a vital need for an alternative, due to the present refining technology, and it is much preferred if this technology is mild (without the application of high temperature and pressure), to minimize pollutant formation, and is flexible in process design (modular, with no restriction of capacity). For the first time, a summary report of the new technologies, such as the chemical-assisted ultrasound and the nanotechnology-aided refining, has been evaluated.

ANALYSIS OF FUTURE SOURCES

Conventional heavy oil sources up to the present are as follows: bottom or residua from delayed coking or vacuum distillation (paving asphalt); fractions after hydrotreatment; native bitumens (native asphaltene and native asphaltites); native asphaltoids (e.g., wuzterlite, ingramite, etc.); oil sand bitumens; pyrolyzed kerogen product mixed with bitumen (oil shale); residue field oil after thermal or fire flooding; mined green oil after well closure (after tertiary recovery process); coal derived liquid, either from stagewise pyrolysis or hydrogenation³.

Due to the geochemical nature of oils from the same geological regions, oils that have been exposed to the same paleogeological environments should be similar. From these aspects, crudes from

different sources are different in composition. Some of the massive reserves of heavy oils have been exploited for commercial use: the Venezuelan bitumen of the Orinoco basin and the heavy oil of Alberta and Saskatchewan, for example, Cold Lake and Lloydminster; continental type of heavy oil from Liaohé and Karamay in China; residua of Maya and Isthmas from Mexico; and immature coastal deposits from California.

As the world turns around the corner of 2000, further potential resources become increasingly important, especially in many localities of the world, which can be extra heavy oil or bitumen: Eocene oil sand at Canbay basin in India; Volga-Urals' natural bitumens in Katakstan and Turkmenistan; Campos basin biodegraded oil in Brazil; Coastal bitumen type of Benin basin in Nigeria; Aswari limestone reservoir deposit in Iran; Duri field heavy oil in Sumatra of Indonesia; Zagros fold belt heavy oil in the Middle East; Narrows graben organic-rich oil shale in Queensland, Australia; Giant Green River oil shale in the U.S. For this study, the worldwide resources of coals, which can liquefy into liquids, are not included.

PRESENT TECHNOLOGY

At present, major, matured, commercial refining and upgrading processes can be summarized as: Foster Wheeler's delayed coking; Exxon's fluid coking and flexicoking (fluid coke gasified with air and steam); HRI-Cities Service's H-oil of ebullating-bed (now Texaco); Amoco's LC-Fining of demetallization and desulfurization (now Lummus Crest); Verba oil's VCC (Verba Combi Cracking) for liquid phase hydrogenation; and catalytic hydrofining; Shell's HYCON for HDM and HDS in series; Petro-Canada's CANMET using ferric sulfate as catalyst; Asahi-Chiyoda-Nippon Mining's SOC (super oil cracking) in slurry phase reactor; IFP-ELF-TOTAL's HYVAHL process.

Even for this short list, thermal cracking is still the major process. The success of a given process is dependent on the marketplace, but one can safely conclude that the combination of more than one is of advantage. A simple example is the combination of thermal cracking and hydrotreatment. Three different modes of hydrocracking are mentioned, which are fixed bed, ebullating bed and moving bed. The addition of a fixed-bed hydrotreater to the existing hydrocracking unit is very effective for the high-quality liquid. In this way often an integrated multi-stage unit is superior when compared to a single-stage unit.

HORIZONTAL DRILLING

Horizontal well steam stimulation has been adopted by a number of companies for pilot tests. For the thermal recovery of heavy oil, the conventional steam stimulation (CSS) and single-well steam circulation (CWSC) for drilling the horizontal length can reach one mile (usually somewhat below 2600 feet in order to avoid drainage of the existing vertical wells). Therein, extension and enlargement of zones can be used for chemicals, physical methods, instruments and microorganisms equally well. If completion work is done in a horizontal well, the layers in the horizontal well serve as both spaces and as individual reactors for further conversion of the oil.

CHEMICAL ASSISTED ULTRASOUND

Since asphaltene and related asphaltics (resin, gas oil, etc. the non-volatiles in petroleum, etc.) in residual oil are very complex in their intermolecular forces among individual species, such as association, assemblage, aggregation, interaction, etc., thermal energy by high temperature heating is not selective and may result in damage. For example, good (premiere) molecules may undergo polymerization and become coke. The effects caused by ultrasound can be attributed to three phenomena. First, there is a rapid movement of fluids caused by a variation of sonic pressure, which subjects the solvent to compression and rarefaction. The second phenomenon, and by far the most important, is cavitation. It is generally accepted that the formation and collapse of microbubbles is responsible for most of the significant chemical effects that are observed. The instantaneous pressure at the center of a collapsing bubble has been estimated from theoretical considerations to be about 75,000 psi. The temperature has been similarly estimated to reach values as high as 5200K. Actually, this technique can be operated at one atmosphere and room temperature. This process is called cold cracking. This violent implosion of the microbubbles also gives rise to luminescence. Thirdly, there is microstreaming, where a large amount of vibrational energy is put into small volumes with little heating. The application of ultrasound frequency for radiation can maintain the range from 25 to 40 kHz at an energy density of 20-600 W/cm². Under the cavitation conditions, two events may occur simultaneously, thermal scission of bonds of heavy oil according to Rice mechanism of cracking, and the generation of hydrogen atoms. These are essential for the upgrading of heavy molecules in residual oil and other residua. Fossil fuels, so far, that have been studied include Athabascar tar sand, Kentucky tar sand, paving asphalt, Monterey crude, coal liquids, Stuart

and Maoming oil shales and the improvement of the quality of reducing the asphaltene content has been found. Furthermore, the ultrasound can be applied in situ for generations of oil by reduction of viscosity using a drilling wanted with a number of transducers.

COLD PLASMA

The often-used control technology for hydrogen sulfide is the Claus method and the process stream after hydrosulfurization from reformer, which has to purify this sour gas through Claus/SCOT unit. All these will lose the value of hydrogen since both processes require oxidation. The microwave method of utilizing the plasma dissociation process has also been developed. The plasma dissociation will save 0.24×10^{12} BTU/y for every 156 ton/d of Claus/SCOT plant.⁵

INTERMETALLIC FILTERS

Most recently, an intermetallic filter specifically for the removal of sulfur and improvement of the quality of feed has been in development.⁶ The surface of Sn-Sb intermetallic has been shown to react with the sulfur species through the adsorption destruction by nanoscale technology. The preliminary results are very encouraging for high sulfur-containing crude oil; in general, a few pass through a fixed bed; the sulfur content has decreased by 50% and the asphaltene has also been reduced by 20%. As indicated in standard textbooks,⁷ a filter can be a biofilter where the microorganisms are applied or an electrokinetic filter (potential difference, applied or induced), where the intermetallics are used. The device is very versatile, which can be attached or connected to any configurations in series or in parallel.

MICROBIAL ENHANCED OIL RECOVERY (MEOR)

Contrary to the Public's understanding, the MEOR method is more efficient for the recovery of heavy oil rather than light oil.⁸ In a horizontally-drilled well, microorganisms can be introduced at certain levels of the pay zone. Very recently, one case has been found that all the recovery methods failed; MEOR is the only successful one.⁹ The advantage of using special thermophiles for fermentation at the bottom of the hole has been described for the future ultimate oil recovery (UOR), as described earlier.¹⁰

CONCLUSION

A challenge is made to produce, transport, and refine the extraordinary crude and bitumens. A recommendation is therefore made for the future of the refining and upgrading industry for applying different, newly developed devices to enhance their efforts.

The use of a successive, multi-step unit (including the pre- and post-treatment unit to the maintrain) is to selectively eliminate the small amounts of bad molecules (molecules containing S, N, X and M), by targeting the destructive power on bad molecules, using a specific frequency of the irradiation (e.g., ultrasound, microwave, cold plasma, electrokinetic, induced field, magnetic force). Conventional refining technology, based on the premise that both good (major) molecules, and bad (minor) molecules, are treated with much excessive power in order to crack the very small amount of bad molecules, is not energy-saving. To achieve success in future refining and upgrading of heavy oil, research should not be centered on catalysts and reactor design alone, but also on the overall interdisciplinary knowledge of the nature of asphaltene pertaining to the geochemical transformation and formation. The recent concept,¹¹ that asphaltene and its related substances are continuous in transformation, is of paramount importance for the conversion.

REFERENCES

1. U.S.DOE, 1990, "Energy Outlook to the Year 2000, An Overview", Washington, D.C.
2. Yen, T.F., 1990, "Asphalt Materials" in *Encyclopedia of Polymer Science and Engineering*, Supplementary Volume, John Wiley, New York, pp. 1-10.
3. Yen, T.F., 1998, "Correlation between Heavy Crude Sources and Types and their Refining and Upgrading Methods," *Proceeding of the 7th UNITAR International Conference on Heavy Crude and Tar Sands*, Beijing, Vol. 2, pp. 2137-2144.
4. Yen, T.F., 1997, "Upgrading Through Cavitation and Surfactant," *Proceedings of the 15th World Petroleum Congress*, Forum 17, John Wiley, London.

5. Goyski, A.J., Daniels, E.J., and Harkness, J.B.L., 1990, *Treatment of Hydrogen Sulfide Waste Gas*, Argonne National Lab., ANL/ESD/TM-14.
6. Duffield, R., German, R., Iacocca, R., and Yen, T.F., 1998, Treatment of Fluids, Irish patent applied by Klinair Environmental Technology Ltd., Dublin, Ireland.
7. Yen, T.F., 1998, Chapter 31, "Filtration," in *Environmental Chemistry: Chemical Principles for Environmental Processes*, Vol. 4B, Prentice Hall, Upper Saddle River, NJ, pp. 1405-1439.
8. Yen, T.F., 1990, *Microbial Enhanced Oil Recovery: Principle and Practice*, CRC Press, Boca Raton, FL.
9. Mei, B.W., et al., 1998, Unpublished Results Jiangnan Petroleum University, Jin-Zhou, China.
10. Yen, T.F., 1995, "Asphaltenes and Improved Oil Recovery," *Proceedings of the 6th UNITAR International Conference on Heavy Crude and Tar Sands*, DOE, Battlesville, OK, pp.231-236.
11. Yen, T.F., 1999, Chapter 2, "The Realms and Definitions of Asphaltenes," in *Asphaltenes and Asphalts* (T.F.Yen and G.V. Chilingar, eds.) Vol. 2, Elsevier Science, Amsterdam, the Netherlands.

COMPARISON OF FUEL PROPERTIES OF PETROLEUM COKES AND COALS USED IN POWER GENERATION

Jun M. Lee, James J. Baker, Jeffrey G. Rolle, Robert Llerena,
A. J. Edmond Co.

1530 West 16th Street, Long Beach, CA 90813

Keywords: petroleum coke, coal, fuel properties

INTRODUCTION

U.S. petroleum coke production is projected to continue to increase, reaching 90,000 st/cd (short tons per calendar day) by the year 2002, primarily due to refining heavier and higher sulfur content crudes [1]. In 1996 the coke production was 86,805 st/cd and 65.7% of the annual production was exports. Green (raw) petroleum cokes are mostly used as utility fuels (about 73% for fuel grade) combining with coal to make fuel in processing industries. Petroleum cokes are produced at refineries using three different types of coking processes: delayed, fluid, and flexicoking. The delayed coker is mostly used at forty-eight refineries. The other fluid coker (4 units) and flexicoker (2 units) are less utilized. Coke products from a delayed coker are classified as shot, sponge or needle coke depending on their chemical and physical characteristics.

Utility companies used 3,852 st/cd of petroleum coke (less than 5% of annual production) as a power plant supplemental fuel blending with coal in 1996, because petroleum coke has advantages of low price (36% lower at \$/st or 46% lower at \$/MMBtu), high heating value, and low ash content [1]. The disadvantages of petroleum coke as a fuel are expense of a dual solid fuel handling and crushing system, high sulfur, high nickel and vanadium content. Normally cokes are blended with coals at 10-20% before burning in boilers because of their low volatile matter and high sulfur content. Average quality of coke burned is: on as-received basis, 13,930-14,820 Btu/lb, 5.5% sulfur, and 0.5-3.8% ash.

Some refineries consume a portion or all of the coke they produce as a solid fuel to generate steam, and more recently, as fuel for cogeneration facilities. An average of 1,767 st/cd of petroleum coke was used within refineries in 1996. Texaco cogeneration power plant at El Dorado refinery, Kansas gasifies a delayed coke to produce syn-gas for a combustion turbine fuel [2]. Typical composition of the delayed coke is: on dry basis, 90% carbon, 4% hydrogen, 4% sulfur, 1.5% nitrogen, 0.5% oxygen, and 0.5% ash. Other coke-fueled cogeneration plants burn 100% delayed coke [3] or 100% fluid coke [1] in a circulating fluidized bed (CFB) steam generator. Delayed coke fines sized to 0.25 in. (6 mm) is fed to the CFB furnace along with crushed limestone. Typical composition of the delayed coke feed is: on dry basis, 89.2% carbon, 3.7% hydrogen, 5% sulfur, 1.8% nitrogen, 0.3% ash, and 15,050 Btu/lb of high heating value (HHV). The coke contains approximately 10.6% moisture.

Cement industry consumes a large portion of fuel-grade petroleum coke (35.5% of world demand) to combust in kilns [1]. The addition of cokes can constitute up to 50% of the fuel mixture and is carefully controlled conducting test burn due to detrimental effects of high sulfur and vanadium content to concrete quality. Sulfur contamination can cause cement cracking and preheater plugging-fouling due to combination with alkalies, and high vanadium content above 500 ppm can cause cement to lose strength. The cement kilns operate as scrubbers, absorbing sulfur and other contaminants into finished cement.

U.S. utility companies consume about 80% of annual coal production (approximately 1,000 million short tons in 1995) burning in boilers to generate electricity [4]. The coal production consists of 60% bituminous, 30% subbituminous, 8% lignite and small percentage of anthracite. U.S. exports annually about 90-110 millions tons (9-11% of total production).

Coal gasification process technologies have been extensively tested in conjunction with integrated gasification combined cycle (IGCC) systems to improve efficiency, environmental performance, and overall cost effectiveness in electric power generation [5]. Several successful demonstration projects are: British Gas/Lurgi gasifier, Texaco Cool Water gasification plant, Shell Coal Gasification Process, Dow Coal Gasification Process (Destec), etc. Full-scale projects are now proceeding in The Netherlands, Germany, Spain and Italy on a commercial basis. Utah (SUFCO) coal, an export western bituminous coal, was the predominate coal gasified at the Texaco Cool Water plant [6] and also tested in the Shell demo-plant [5]. Typical coal properties are: 0.4% sulfur, 8.8% ash, 12,360 Btu/lb (HHV), and 2,200 deg F of ash fusion temperature. The SUFCO Utah coal has low sulfur, low iron and high sodium content. Shell demo-plant tested a delayed coke which has low ash, high sulfur, low oxygen, low calcium, high vanadium, and high nickel

content. Feed properties of the delayed coke are: on dry basis, 10.6% volatile matter, 0.5% ash, 5.2% sulfur, 89.3% carbon, 3.6% hydrogen, 1.35% nitrogen, 0.03% chlorine, 0.1% oxygen, 15,350 Btu/lb (HHV), and 61 hardgrove grindability index (HGI). The coke contains 9.3% moisture and ash mineral analysis shows 0.8% lime, 1.2% sodium oxide, 71.8% vanadium pentoxide, and 7.4% nickel oxide. Texaco and Kellogg (KRW) gasification processes also extensively tested petroleum cokes as raw material to gasifier [7,8].

Coal ash is classified into two categories: lignitic ash is defined as having more (CaO+MgO) than ferric oxide; and bituminous ash is defined as having more ferric oxide than the sum of CaO and MgO. The Utah coal is classified a western high volatile bituminous coal, but has lignitic ash. Ash characterization methods such as slagging and fouling indices are different in calculation depending upon bituminous or lignitic ash [9]. Chemical composition of coal ash affects slag viscosity, which is an important criterion for determining the suitability of a coal ash for use in a slag-tap cyclone furnace. Slag flow readily at or below a viscosity of 250 poise. The temperature at which this viscosity of ash occurs is called T_{250} temperature. The preferred maximum T_{250} for wet-bottom applications is 2,450 deg F.

The alkali metals, sodium and potassium, have long been associated with the fouling tendencies of coal ash. Correlations in fouling index have been developed using various parameters such as strength of sintered fly ash and total alkali content for bituminous ash, and sodium content alone for lignitic ash. All bituminous coals contain enough sulfur and alkali metals to produce corrosive ash deposits on superheaters and reheaters, and those containing more than 3.5% sulfur and 0.25% chlorine may be particularly troublesome. The elements in coal ash corrosion are sodium, potassium, aluminum, sulfur and iron, which are derived from the mineral matter in coal. Fouling observed in a CFBC boiler firing coal and petroleum coke was attributed to agglomeration of sulfate and carbonate, not due to high concentration of nickel and vanadium present in petroleum coke (306 and 870 ppm, respectively) [10].

The objective of this study is to evaluate and compare various fuel properties of petroleum cokes and bituminous coals used in power generation, comparing different cokes produced from several refineries in U.S. and export western coals sampled at the Los Angeles Export Terminal (LAXT). Four fluid cokes, fourteen delayed cokes and five export coals are included for evaluation based on recent analysis data accumulated for the past two years (1997-1998).

SAMPLING, PREPARATION AND ANALYTICAL METHODS

Representative samples of petroleum cokes and coals have been obtained from various refineries located in California, Texas, Louisiana, Kansas, Illinois and other states, and storage facilities at numerous national ports. Laboratory samples are prepared for fuel properties analysis following the procedures and principles in handling listed in the ASTM Methods D 346, D 2013 and D 2234. Laboratory test methods using various advanced analytical instruments are described in the Quality Assurance Manual of A. J. Edmond Company [11].

RESULTS AND DISCUSSION

Important fuel properties of three significantly different types, delayed coke, fluid coke and export western coal are presented for comparison in Tables 1-3. Petroleum cokes evaluated for this study are produced in various U.S. refineries located in west coast (WC), Gulf coast (GC), mid west (MW), and south east (SE), which are primarily consumed in export to foreign countries (65.7%) and in smaller extent (less than 10%) used in domestic power generation and cement kiln fuel mix. Export western coals sampled at the LAXT are high volatile bituminous coals with low sulfur and iron content. They are primarily produced in Utah and Colorado for power generation. The throughput capacity of LAXT is 10 million metric tons per year, which is correspondent to about 10% of current coal export to foreign countries.

Based on data presented in Tables 1-3, five different arbitrary groups of concentration or value of several primary fuel properties are used as indicators of different levels of properties as follows:

| Fuel Property | Very Low | Low | Medium | High | Very High |
|----------------------|----------|-------------|-------------|-------------|-----------|
| Sulfur, wt% | | 1-2 | 2-4 | 4-6 | |
| Ash, wt% | 0.5 | 1-2 | | 9-10 | |
| Volatile Matter, wt% | | 2.5-6.1 | 9.5-13 | 40.2-41.1 | |
| Btu/lb | | 12600-13400 | 14200-14600 | 15200-15600 | |
| Nitrogen, wt% | | 1.2-2.2 | | 2.8-3.2 | |
| Vanadium, ppm | | 270-400 | 500-800 | 900-1400 | 2300-2900 |
| Nickel, ppm | | 25-200 | 400-500 | 700+ | |

Fluid Coke Fuel for Cogeneration Plants

Table 1 summarizes analysis results of fuel properties of petroleum cokes used in power generation. Three fluid cokes (WC-1, WC-2 and WC-3), one bed coke (WC-4) and six delayed cokes (WC-5, SW/MW-1, SW/MW-2, SE, SE/GC, E/MW) are included for comparison. Fluid and bed cokes (WC-1 to WC-4) have been extensively used in circulating fluidized bed combustors at cogeneration power plants. WC-2 and WC-3 fluid cokes also represent export quality to foreign countries.

Fluid coke generated from a fluidized bed reactor is a solid, spherical particulate normally smaller than 8 mesh (98% for WC-2 and WC-3, and 74% for WC-4, as shown in Table 1). The coke is very hard and abrasive, suitable for direct use in a circulating fluidized bed combustor, and generally have lower HGI than delayed coke and coal. Typical moisture content is very low in the range of 0.3 to 1.2% except for export cokes having 7-11.5% which increased to control dust during transportation. Sulfur content for fluid cokes, WC-1, WC-3 and WC-4, is low in the range of 1.0 to 2.1%; and WC-2 coke has medium sulfur with 3.3%, somewhat lower than other delayed cokes listed in Table 1 (4-6%). Ash content of WC-1 and WC-2 cokes is very low in the range of 0.35 to 0.46%, and WC-1 and WC-2 cokes have a little higher ash from 1.1 to 1.5%. These ash values are significantly lower compared to coals (9.2-10%), which is normally claimed as an advantage as fuel.

Calorific value for all fluid cokes studied is medium in the range of 14,200-14,400 Btu/lb (dry basis), relatively high compared to coals (12,600-13,400 Btu/lb dry basis). Volatile matter content is low in the range of 2.5 to 6.1% for all fluid cokes, compared to delayed cokes (9.5-13%) and coals (40.2-41.1%). Power plant startup is easier with fuels having higher volatile matter. However, serious operational problems in burning petroleum cokes as 100% or 10-20% blend mix have not been reported. Fluid cokes, WC-2, WC-3 and WC-4, have relatively low nitrogen content in the range of 1.4 to 2.2%, while WC-1 has a higher nitrogen of 3%, similarly observed with some delayed cokes (2.8-3.2%). Coals evaluated for this study have a low nitrogen of 1.2 to 1.5%.

Vanadium content for WC-1 and WC-2 is medium in the range of 650 to 850 ppm, near concentration used in the cement kiln fuel mix (530-760 ppm for SW/MW-1 and SW/MW-2), but higher than that for good anode-grade cokes (270-400 ppm). WC-3 and WC-4 cokes show the highest V content in the range of 2300 to 2900 ppm among petroleum cokes and coals evaluated for this study. Detrimental affects with this high V content (as much as 10,000 ppm) have not been reported in the operation of steam generating combustors [12]. Sodium content for WC-1 and WC-2 cokes is low in the range of 80 to 180 ppm, which is similarly observed in good anode-grade sponge cokes (25-200 ppm). WC-3 and WC-4 cokes have a higher Na content of 480 to 500 ppm compared to WC-1 and WC-2. Most of delayed cokes studied have a low Na content (50-160 ppm) except for WC-5 and WC-E4 (380-450 ppm).

Delayed Coke Fuel for Utility and Cement Plants

Six delayed cokes in Table 1 (WC-5, SW/MW-1, SW/MW-2, SE, SE/GC, E/MW) have been used as fuel blend mix in pulverized coal combustors for steam generation and cement kilns. These cokes are fuel grade, green (raw) cokes with high ash, high sulfur and high metal content ranging from sponge to shot coke. Typical ash content is in the range of 0.25 to 0.65%; sulfur content in the range of 3.1 to 6%; vanadium from 530 to 1700 ppm; nickel from 190 to 600 ppm; and sodium from 80 to 380 ppm. Calorific value is high in the range of 15,000 to 15,580 Btu/lb (HHV, dry basis), producing more heat during combustion than fluid cokes and coals. Size distribution covers wide range of particle size from -6 mm to +40 mm depending on fines, lump or ROC (run of coker) delivered from refineries. Typical HGI is in the range of 35 to 60, mostly higher than coal HGI (45), with shot content varying from 0 to 80%. Typical moisture content is in the range of 5 to 9%, and volatile matter varies from 9.5 to 13%.

Two delayed cokes, SW/MW-1 and SW/MW-2 have been frequently used in cement kiln operation, as fuel mix (up to 50%). Typical sulfur and vanadium content (controlled quality parameters for cement application) of these cokes vary in the range of 3.1 to 3.8% and 530 to 760 ppm, respectively. Sulfur and vanadium content are higher than those required for good anode-grade sponge coke (3% and 400 ppm, respectively).

Quality of Export Petroleum Cokes

Table 2 presents analysis results from eight export delayed cokes. These cokes have been mostly used as utility fuels combining with coal to make fuel in processing industries. Fuel property data in the table update export quality analysis of petroleum cokes previously reported [11]. Export quality criteria of green (raw), fuel-grade cokes are dependent upon buyer's requirements of coke specifications. As shown in the following for west coast cokes, primary criteria frequently used

are: size distribution, moisture, sulfur, ash, volatile matter, fixed carbon content and calorific value; and secondary criteria are: nitrogen, vanadium and sodium content. In addition, complete ash mineral analysis is sometimes required to report.

| Fuel Property | Criteria Specified |
|---------------------------|----------------------------|
| Size, mm | 0x6, 0x10 or lump -2 & +25 |
| Moisture, wt% (dry basis) | 8-12, 9-12 or 9 max |
| Sulfur, wt% | 1 max, 2 max or 3 max |
| Ash, wt% | 0.5 max, 1 max or 1.5 max |
| Volatile Matter, wt% | 9-13, 11-12.5 or 14 max |
| Fixed Carbon, wt% | 88-90 or 87 min |
| HGI | 45-50 or 50 min |
| Btu/lb | 15,000 min |
| Nitrogen, wt% | 2, 2.5-3.5 or 2.9 max |
| Vanadium, ppm | 500-800 or 700 max |
| Sodium, ppm | 200-300 or 700 max |

Eight delayed cokes in Table 2 (WC-E1 to WC-E8) are produced in refineries located in west coast. These cokes are good quality, fuel-grade green (raw) cokes, which generally have lower ash, sulfur and metal content than six delayed cokes in Table 1 used in domestic power generation. Typical ash content is in the range of 0.18 to 0.45%; sulfur content in the range of 0.8 to 4%; vanadium from 270 to 1150 ppm; nickel from 180 to 550 ppm; and sodium from 50 to 450 ppm. Calorific value is high in the range of 15,300 to 15,520 Btu/lb (HHV, dry basis), as similarly observed with delayed cokes in Table 1. Size distribution covers wide range of particle size from -6 mm (30-99%) with fines, to +40 mm (3-47%) with lump or ROC (run of coker) depending on delivery from refineries. Typical HGI is in the range of 35 to 80, mostly higher than coal HGI (45), with shot content varying from 0 to 60%. Typical moisture content is in the range of 7 to 12%, and volatile matter varies from 10 to 12.5%.

Quality of Export Western Coals

Table 3 summarizes analysis results from five export western coals (type I to V). These coals sampled at the LAXT are high volatile bituminous coals with low sulfur and iron content. They are primarily produced in Utah and Colorado and used as utility fuels for power generation. Coal quality specifications for export were previously reported [11]. Primary fuel properties of coal are: proximate, ultimate, calorific value, HGI, size distribution, ash mineral analysis and ash fusion temperatures.

Typical ash content of export western coals is high in the range of 9.2 to 10%; sulfur content is very low in the range of 0.45 to 0.6%. These coals are classified as western high volatile bituminous coal, but have lignitic ash having more (CaO+MgO) than ferric oxide [9]. Primary constituents of coal ash are silica (52.3-58.6%), alumina (11.6-21%) and lime (5-13.1%). Ferric oxide content in ash is low from 4.4 to 5.9% compared to eastern bituminous coal (20-30%); sodium oxide content is high from 1.8 to 4.2%. Calorific value is low in the range of 12,640 to 13,360 Btu/lb (HHV, dry basis), compared to fluid cokes and delayed cokes in Tables 1 and 2. Size distribution shows top size of 2 inches having 92-100% 50 mm x 0 mm and 11.6-33% 2 mm x 0 mm. Typical HGI is in the range of 43 to 46. Typical moisture content is in the range of 7.7 to 10.3%, and volatile matter varies from 40.2 to 41.1%.

Data for coal ash characteristics used for selection of feed coal and boiler design criteria are also presented in Table 3. Ash and slag viscosity plot parameters are: silica ratio, base-to-acid (B/A) ratio, T_{250} , and slagging index. Fouling plot parameters are: alkalis as sodium oxide and fouling index [9]. Typical silica ratio is in the range of 0.712 to 0.828; B/A ratio from 0.2 to 0.386; T_{250} from 2,420 to 2,760 deg F; and slagging index is medium to high in the range of 2,114 to 2,263. Typical alkalis as sodium oxide is high in the range of 2.5 to 4.5; and fouling index is high from 1.8 to 4.2. Very low sulfur content with these coals may lower corrosive ash deposits caused by reacting with sodium, potassium, aluminum and iron, but addition of high sulfur petroleum cokes as fuel mix may increase corrosion reactions with alkali metals. Coal type III and V with high B/A ratio of 0.386 and 0.372 have low T_{250} (2,420 and 2,450 deg F, respectively) meeting requirement for operation of slag-tap cyclone furnace.

SUMMARY

Various fuel properties of four fluid cokes, fourteen delayed cokes and five export western coals were analyzed and are compared for use in power generation. Important fuel quality parameters (typical and range) are tabulated for comparison, using recent analysis data accumulated for the

past two years (1997-1998). Primary properties evaluated are: heating value, sulfur, nitrogen, ash, moisture, volatile matter content, hardgrove grindability index, size distribution, and mineral analysis. In addition, coal ash characteristics such as silica ratio, base-to-acid ratio, ash fusibility, alkalis, T_{250} , slagging index, fouling index, etc. are discussed.

Petroleum cokes as 100% fuel or 10-20% fuel mix with coal have been used in power generation without serious operational problems reported, even burning with some cokes of high vanadium content (1,000-3,200 ppm). Some cokes have high sulfur content up to 7%, high nitrogen content up to 3.5%, and low HGI down to 25 (for delayed coke). Typical sulfur content of most cokes studied varies in the range of 0.8 to 4.1%; nitrogen varies in the range of 1.3 to 3.2%; and HGI varies from 40 to 80 (for delayed coke), mostly higher than coal HGI (45).

Petroleum cokes as fuel mix (up to 50%) have been used in cement kiln operation. Typical sulfur and vanadium content (controlled quality parameters for cement application) of delayed cokes mixed in kiln vary in the range of 3.1 to 3.8% and 530 to 760 ppm, respectively.

Export delayed cokes are good quality, fuel-grade green (raw) cokes, which generally have lower ash, sulfur and metal content than delayed cokes used in domestic power generation. Typical ash content is in the range of 0.18 to 0.45%; sulfur content from 0.8 to 4%; vanadium from 270 to 1,150 ppm; nickel from 180 to 550 ppm; and sodium from 50 to 450 ppm. Calorific value is high in the range of 15,300 to 15,520 Btu/lb (HHV, dry basis).

Price of fuel grade petroleum coke is normally below 5 \$/ton at refinery, however, transportation cost significantly increases the price at power plant (21 \$/ton, 1996 annual average delivered). Demand and supply of petroleum coke are dictated by three important factors such as refinery cost, coke quality and transportation cost. Location of refinery and power plant seems an important factor to be considered.

Export western coals are high volatile bituminous coals with low sulfur and iron content, and are used as utility fuels for power generation. Typical ash content is high in the range of 9.2 to 10%; sulfur content is very low in the range of 0.45 to 0.6%. Ash from these coals are defined as lignitic ash having more (CaO+MgO) than ferric oxide. Ferric oxide content in ash is low from 4.4 to 5.9% compared to eastern bituminous coal (20-30%); sodium oxide content is high from 1.8 to 4.2%. Calorific value is low in the range of 12,640 to 13,360 Btu/lb (HHV, dry basis), compared to petroleum cokes. Coal ash characteristics used for selection of feed coal and boiler design criteria are discussed relating to slag viscosity, fouling, and corrosion. Coal type III and V have low T_{250} , meeting requirement for operation of slag-tap cyclone furnace.

The SUFCO Utah coal, one of five export western bituminous coals evaluated for this study, was extensively tested at several gasification demonstration plants for IGCC systems in addition to variety of petroleum cokes as feed material to gasifiers.

REFERENCES

1. E. J. Swain, Oil & Gas Journal, Nov. 10, 1997, 79-82; May 20, 1991, 49-52.
2. A. K. Rhodes, Oil & Gas Journal, Aug. 5, 1996, 31-35.
3. K. W. Richardson and F. D. Taibi, Oil & Gas Journal, Apr. 5, 1993, 38-42.
4. R. Graham, ASTM Standardization News, Mar. 1998, 36-43.
5. Kerk-Othmer Encyclopedia of Chemical Technology, Volume 6, 4th Ed., Gasification, 541-568 (1993).
6. D. H. Watts, Sixth Annual International Pittsburgh Coal Conference, Sep. 25-29, 1989, 569-581.
7. A. M. Robin, et. al., Sixth Annual International Pittsburgh Coal Conference, Sep. 25-29, 1989, 244-254.
8. F. M. Floyd and R. K. Agrawal, Sixth Annual International Pittsburgh Coal Conference, Sep. 25-29, 1989, 559-568.
9. Babcock & Wilcox Company, "Steam - Its Generation and Use: Steam 40", Chap. 20, Fuel Ash Effects on Boiler Design and Operation (1992).
10. E. J. Anthony, et. al., 215th ACS National Meeting, Dallas, Preprints of Symposia, Division of Fuel Chemistry, Vol. 43, No. 1, 163-166 (1998).
11. J. M. Lee, J. J. Baker, R. Llerena, J. G. Rolle, 214th ACS National Meeting, Las Vegas, Preprints of Symposia, Division of Fuel Chemistry, Vol. 42, No. 3, 844-853 (1997).
12. R. W. Bryers, ACS National Meeting, Preprints of Symposia, Division of Fuel Chemistry, Vol. 38, No. 4, 1237-1244 (1993).

Table 1. FUEL PROPERTIES OF FLUID AND DELAYED COKES USED IN POWER GENERATION

| Industry Location | WC-1 | | WC-2 | | WC-3 | | WC-4 | | WC-5 | |
|-----------------------------|----------------|---------|-------|----------------|-------|-----------|-------|-----------|--------------|-----------------|
| | Cogeneneration | | CFBC | | CFBC | | CFBC | | PCC | |
| | Fluid | Typical | Fluid | Typical | Fluid | Typical | Fluid | Typical | Cement K'lIn | Delayed (Blend) |
| Coke Type | | | | | | | | | | |
| Proximate, wt% | | | | | | | | | | |
| Moisture, wt% (as-received) | 0.5 | 0.2-1.4 | 0.3 | 0.02-0.8 | 11.5 | 10-15 | 1.2 | 0.2-2.5 | 9 | 4-13 |
| Moisture, wt% (dry-basis) | | | | (Export: 6-8%) | | | | | | |
| Proximate, wt% | | | | | | | | | | |
| VCM | 6.1 | 5.7 | 5.3 | 4.7 | 4.6 | 2.9-7.5 | 2.5 | 1.6-3.1 | 13 | 11-15 |
| Ash | 0.46 | 0.3-0.6 | 0.35 | 0.25-0.5 | 1.1 | 0.7-1.2 | 1.5 | 1.2-1.9 | 0.65 | 0.3-0.7 |
| FC (by diff.) | 93.4 | 93-94.5 | 94.3 | 93.4-95.2 | 94.3 | 91.5-96.5 | 95.6 | - | 86.5 | 85-88 |
| Ultimate, wt% | | | | | | | | | | |
| Sulfur | 2.1 | 1.5-2.5 | 3.3 | 3.0-3.6 | 1.2 | 0.8-2.5 | 1.0 | - | 4.6 | 3.8-5.5 |
| Carbon | 92.2 | 91.6-93 | 91.7 | 91.9-92.5 | 94.8 | - | 94.6 | - | 86.5 | - |
| Hydrogen | 1.7 | 1.3-2.2 | 2.0 | 1.8-2.2 | 1.0 | - | 0.8 | - | 3.8 | - |
| Nitrogen | 3.0 | 2.7-3.4 | 2.2 | 1.8-2.4 | 1.4 | - | 1.7 | - | 2.8 | 2.8-3.1 |
| Oxygen (by diff.) | 0.54 | - | 0.45 | - | 0.5 | - | 0.4 | - | 1.95 | - |
| Chlorine (ppm) | - | - | 160 | 70-260 | - | - | - | - | 265 | - |
| Analysis, ppm | | | | | | | | | | |
| Silicon | 150 | 80-200 | 150 | 60-230 | 350 | 100-570 | 400 | 230-530 | 150 | 100-210 |
| Iron | 380 | 230-500 | 150 | 110-240 | 1600 | 1080-2060 | 1600 | 1120-2060 | 170 | 80-290 |
| Vanadium | 650 | 430-860 | 850 | 700-1130 | 2300 | 1940-2750 | 2900 | 2670-3200 | 1700 | 1400-2100 |
| Nickel | 620 | 480-700 | 450 | 400-540 | 2200 | 2050-2840 | 2350 | 2050-2630 | 600 | 490-730 |
| Aluminum | 45 | 10-95 | 80 | 40-200 | 90 | 50-180 | 100 | 30-160 | 70 | 20-170 |
| Calcium | 210 | 160-290 | 120 | 40-210 | 800 | 420-1140 | 800 | 500-1030 | 200 | 140-360 |
| Sodium | 180 | 90-250 | 80 | 40-170 | 480 | 340-740 | 500 | 290-740 | 380 | 200-510 |
| Calorific Value | | | | | | | | | | |
| Btu/lb | 14540 | 14280 | 14550 | 14300 | 14330 | 14200 | 14200 | - | 15000 | 14900 |
| HHV | - | -14700 | - | -14750 | - | -14480 | - | - | -15150 | - |
| Slrat. % | | | | | | | | | | |
| Size, wt% | - | - | - | - | - | - | - | - | 60 | 50-67 |
| +4 mesh | - | - | 98.6 | - | 97.7 | 0 | - | - | 0 | 0-5 |
| +8 mesh | - | - | - | - | - | 2 | - | - | - | - |
| +16 mesh | - | - | - | 1.5 | - | - | - | - | - | - |
| +50 mesh | - | - | - | 94 | - | - | - | 74 | - | - |
| +100 mesh | - | - | - | 52 | - | 38 | - | 24 | - | - |
| +200 mesh | - | - | - | 4 | - | 7 | - | 7 | - | - |
| Fuel Ratio | 15.3 | - | 17.8 | - | 20.5 | - | 38.2 | - | - | 6.7 |

Table 1. FUEL PROPERTIES OF FLUID AND DELAYED COKES USED IN POWER GENERATION (Continued)

| Industry Location | SW/MW-1 | | | SW/MW-2 | | | SE | | | SE/GC | | | E/MW | | |
|-------------------|---------|-------------|-----------------|---------|-------------|-----------------|---------|-------------|-----------------|-----------|-------------|-----------------|---------|-------------|-----------------|
| | PCC | Cement Klin | Delayed (Blend) | PCC | Cement Klin | Delayed (Blend) | PCC | Cement Klin | Delayed (Blend) | PCC | Cement Klin | Delayed (Blend) | PCC | Cement Klin | Delayed (Blend) |
| Coke Type | Typical | Range | Typical | Typical | Range | Typical | Typical | Range | Typical | Typical | Range | Typical | Typical | Range | Typical |
| Proximates | | | | | | | | | | | | | | | |
| Moisture, wt% | 5 | 2-10 | 5 | 1-10 | 7 | 1-24 | 8 | 5-14 | 8 | 7-13 | | | | | |
| (dry-basis) | | | | | | | | | | | | | | | |
| Proximate, wt% | | | | | | | | | | | | | | | |
| VCM | 10.5 | 9.8-11.1 | 11 | 9-14 | 11 | 7-13 | 10.5 | 9-12 | 9.5 | 8.6-10.5 | | | | | |
| Ash | 0.28 | 0.21-0.32 | 0.28 | 0.2-0.4 | 0.45 | 0.3-0.6 | 0.52 | 0.35-0.85 | 0.32 | 0.2-0.53 | | | | | |
| FC (by diff.) | 89.2 | 88.7-90 | 88.6 | 87-90 | 88.5 | 87-92 | 89.0 | 87-91 | 90.2 | 89.3-91.2 | | | | | |
| Ultimate, wt% | | | | | | | | | | | | | | | |
| Sulfur | 3.1 | 2.8-3.6 | 3.8 | 2.9-4.9 | 5 | 3.5-6.5 | 6.0 | 5-7 | 4.1 | 3.3-5.8 | | | | | |
| Carbon | - | - | 89.8 | - | - | - | 86.8 | 85-89 | 89.9 | 89.91 | | | | | |
| Hydrogen | - | - | 3.9 | - | - | - | 3.8 | 3.6-4.0 | 3.6 | 3.4-3.9 | | | | | |
| Nitrogen | - | - | 1.3 | - | 1.8 | 1.4-2.2 | 1.7 | 1.5-1.8 | 1.5 | 1.1-2.2 | | | | | |
| Oxygen (by diff.) | - | - | 0.92 | - | - | - | 1.2 | - | 0.58 | - | | | | | |
| Chlorine (ppm) | - | - | 130 | 50-200 | - | - | 200 | 100-300 | 270 | - | | | | | |
| Metals, ppm | | | | | | | | | | | | | | | |
| Silicon | 60 | - | 85 | - | 150 | 50-310 | 140 | 50-300 | 80 | - | | | | | |
| Iron | 300 | - | 650 | - | 200 | 50-550 | 200 | 100-400 | 230 | - | | | | | |
| Vanadium | 530 | 450-610 | 750 | 540-860 | 1400 | 1100-1900 | 1100 | 530-1650 | 730 | 600-890 | | | | | |
| Nickel | 190 | - | 240 | 220-280 | 380 | 260-450 | 300 | 250-350 | 350 | 210-550 | | | | | |
| Aluminum | 10 | - | 30 | - | 70 | - | 100 | 50-200 | 40 | - | | | | | |
| Calcium | 80 | - | 90 | - | - | - | 150 | 50-300 | 160 | - | | | | | |
| Sodium | 130 | - | 100 | - | 100 | - | 80 | 50-150 | 130 | - | | | | | |
| Calorific Value | | | | | | | | | | | | | | | |
| Btu/lb | 15580 | 15360 | 15500 | 15350 | 15350 | 15170 | 15240 | 15050 | 15450 | 15350 | | | | | |
| High | - | -15710 | -15750 | -15750 | -15480 | -15480 | -15480 | -15400 | -15600 | -15600 | | | | | |
| Heat, % | 50 | 41-56 | 50 | 40-70 | 50 | 30-80 | 48 | 35-70 | 35 | 28-51 | | | | | |
| Size, wt% | 80 | 40-100 | 50 | 0-100 | 60 | 0-100 | 75 | 40-100 | 60 | 5-90 | | | | | |
| +40 mm | - | - | - | - | - | - | (ROC) | +30 mm | - | - | | | | | |
| 40x30 mm | - | - | - | - | - | - | - | 30x15 | - | - | | | | | |
| 20x12 mm | - | - | - | - | - | - | - | -15 | - | - | | | | | |
| 12x6 mm | - | - | - | - | - | - | - | - | - | - | | | | | |
| -6 mm | - | - | - | - | - | - | - | - | - | - | | | | | |
| 200 mesh | - | - | - | - | - | - | - | - | - | - | | | | | |
| Fuel Ratio | 8.5 | - | 8.1 | - | 8.1 | - | 8.5 | - | 9.5 | - | | | | | |

Table 2. FUEL PROPERTIES OF EXPORT DELAYED COKES USED IN POWER GENERATION

| Industry Location Process | WC-E1 | | | WC-E2 | | | WC-E3 | | | WC-E4 | | | WC-E5 | | |
|------------------------------|--------------------|-----------------|---------|--------------------|-----------------|---------|--------------------|-----------------|---------|--------------------|-----------------|-------|--------------------|-----------------|-------|
| | Export PCC, etc | Delayed (Blend) | Range | Export PCC, etc | Delayed (Blend) | Range | Export PCC, etc | Delayed (Blend) | Range | Export PCC, etc | Delayed (Blend) | Range | Export PCC, etc | Delayed (Blend) | Range |
| <i>Procedias</i> | | | | | | | | | | | | | | | |
| (as received) | | | | | | | | | | | | | | | |
| Moisture wt% | 9 | 5-13 | 7 | 5-11 | 10 | 8-14 | 10 | 6-14 | 10 | 7-14 | | | | | |
| (dry basis) | | | | | | | | | | | | | | | |
| <i>Ultimate, wt%</i> | | | | | | | | | | | | | | | |
| VCMI | 11.5 | 10-13 | 10 | 9-11.5 | 11.5 | 10-13 | 11.5 | 10-13.5 | 10 | 9-12 | | | | | |
| ASH | 0.2 | 0.1-0.4 | 0.4 | 0.3-0.5 | 0.35 | 0.3-0.6 | 0.35 | 0.25-0.45 | | | | | | | |
| FC (by diff.) | 88.3 | - | 89.6 | - | 88.1 | - | - | 89.6 | - | - | - | - | - | - | - |
| <i>Ultimate, wt%</i> | | | | | | | | | | | | | | | |
| Sulfur | 0.8 | 0.7-1.1 | 1.2 | 0.9-1.4 | 1.3 | 1.1-1.8 | 2.7 | 2.5-3.1 | 2.9 | 2.3-3.4 | | | | | |
| Carbon | 90.5 | 89.5-91.6 | 90.5 | 89.8-91.7 | 90.2 | 89.91 | 89.0 | 88.8-89.3 | 89.4 | 88.5-89.9 | | | | | |
| Hydrogen | 4.1 | 3.9-4.3 | 3.9 | 3.8-4 | 4.0 | 3.8-4.2 | 3.9 | 3.7-4.1 | 3.9 | 3.7-4.1 | | | | | |
| Nitrogen | 3.2 | 3-3.8 | 3.1 | 2.7-3.3 | 3.2 | 2.7-3.4 | 2.8 | 2.7-3.0 | 2.8 | 2.5-3.2 | | | | | |
| Oxygen (by diff.) | 1.20 | - | 0.9 | - | 0.95 | - | 1.15 | - | 0.65 | - | - | - | - | - | - |
| Chlorine (ppm) | 150 | 90-280 | 180 | 110-320 | - | - | - | 200 | - | 90-270 | | | | | |
| <i>Metals, ppm</i> | | | | | | | | | | | | | | | |
| Silicon | 80 | 20-240 | 110 | 60-260 | 150 | 50-360 | 100 | 30-200 | 70 | 40-220 | | | | | |
| Iron | 230 | 120-380 | 340 | 280-430 | 270 | 180-400 | 300 | 170-500 | 350 | 160-640 | | | | | |
| Vanadium | 270 | 230-330 | 600 | 450-720 | 550 | 470-720 | 900 | 690-1200 | 900 | 780-1060 | | | | | |
| Nickel | 540 | 480-640 | 550 | 490-720 | 500 | 440-610 | 500 | 430-560 | 520 | 400-650 | | | | | |
| Aluminum | 40 | 10-100 | 100 | 40-210 | 120 | 40-220 | 50 | 20-150 | 40 | 10-110 | | | | | |
| Calcium | 50 | 20-110 | 190 | 170-220 | 230 | 90-400 | 150 | 90-300 | 100 | 50-210 | | | | | |
| Sodium | 70 | 40-140 | 110 | 80-160 | 160 | 80-210 | 450 | 360-670 | 140 | 90-220 | | | | | |
| <i>Calorific Value</i> | | | | | | | | | | | | | | | |
| Btu/lb | 15450 | 15300 | 15450 | 15350 | 15500 | 15400 | 15350 | 15200 | 15350 | 15200 | | | | | |
| kg/l | 50 | 50-70 | 40 | 30-52 | 50 | 40-65 | 55 | 45-75 | 35 | 25-40 | | | | | |
| Size, wt% | 40 | 5-80 | 60 | 20-100 | 20 | 5-60 | 30 | 0-80 | 60 | 10-90 | | | | | |
| +40 mm | (Fines) | (ROC) | (Fines) | (ROC) | (ROC) | (Lump) | (Fines) | (Lump) | (Fines) | (Lump) | | | | | |
| 40x30 mm | - | - | - | 0-5 | 0-8 | 21-54 | 4-19 | 13-45 | 0 | 5-25 | | | | | |
| 20x12 mm | - | - | 0-1 | 9-26 | 0-18 | 10-36 | 7-32 | 10-34 | 3 | 11-89 | | | | | |
| 12x6 mm | - | - | 1-4 | 2-9 | 3-22 | 1-19 | 22-55 | 1-23 | 6 | 5-26 | | | | | |
| 6mm | - | - | 96-99 | 65-98 | 39-88 | 1-49 | 30-61 | 1-39 | 91 | 11-55 | | | | | |
| 200 mesh | 9 | - | - | - | 8 | - | 9 | - | 9 | - | | | | | |
| <i>Fuel Ratio</i> | | | | | | | | | | | | | | | |
| | 7.7 | - | 9.0 | - | 7.7 | - | 7.7 | - | 9.0 | - | | | | | |

Table 2. FUEL PROPERTIES OF EXPORT DELAYED COKES USED IN POWER GENERATION (Continued)

| Industry Location | WC-E6 Export PCC, etc. Delayed (Blend) Typical Range | WC-E7 Export PCC, etc. Delayed (Blend) Typical Range | WC-E8 Export PCC, etc. Delayed (Blend) Typical Range | | | | | | |
|----------------------------|--|--|--|-----------|---------|-----------|--|--|--|
| Coke Type (as-received) | | | | | | | | | |
| Moisture, wt% | 11.5 | 9-15 | 8 | 5-13 | 12 | 8-20 | | | |
| (dry-basis) | | | | | | | | | |
| Volatile, wt% | | | | | | | | | |
| VCM | 11.5 | 10-13 | 10 | 8-11 | 12.5 | 11.4-14.4 | | | |
| FC (by diff.) | 0.2 | 0.18-0.33 | 0.18 | 0.08-0.41 | 0.31 | 0.26-0.44 | | | |
| Ash | 88.3 | 87.2-89.8 | 89.8 | 88.4-91.3 | 87.2 | 86.2-88.3 | | | |
| Ultimate, wt% | | | | | | | | | |
| Sulfur | 3.5 | 2.4-5 | 2.9 | 2.6-3.2 | 4 | 2.7-5.2 | | | |
| Carbon | 89.7 | 88.5-90.8 | 90.7 | 89.8-91.4 | 89.5 | 88.5-90.5 | | | |
| Hydrogen | 3.9 | 3.7-4.1 | 3.8 | 3.7-3.9 | 3.8 | 3.6-3.9 | | | |
| Nitrogen | 2.0 | 1.7-2.4 | 1.6 | 1.4-1.8 | 2.1 | 1.7-2.4 | | | |
| Oxygen (by diff.) | 0.7 | - | 0.82 | - | 0.29 | - | | | |
| Chlorine (ppm) | - | - | 220 | - | - | - | | | |
| Metals, ppm | | | | | | | | | |
| Silicon | 70 | 20-230 | 60 | 20-190 | 70 | 40-130 | | | |
| Iron | 220 | 110-320 | 70 | 30-180 | 130 | 100-180 | | | |
| Vanadium | 370 | 300-560 | 370 | 300-440 | 1150 | 960-1280 | | | |
| Nickel | 310 | 250-400 | 180 | 130-230 | 460 | 430-600 | | | |
| Aluminum | 45 | 20-100 | 30 | 30-90 | 20 | 10-40 | | | |
| Calcium | 80 | 30-200 | 40 | 20-100 | 80 | 40-140 | | | |
| Sodium | 80 | 40-160 | 50 | 30-90 | 110 | 100-130 | | | |
| Calorific Value | | | | | | | | | |
| Btu/lb | 15520 | 15350 | 15500 | 15400 | 15400 | 15330 | | | |
| HGI | - | -15620 | 55 | -15630 | - | -15460 | | | |
| Shat. % | 80 | 60-96 | 85 | 35-75 | 70 | 64-83 | | | |
| Size, wt% | 0 | 0-5 | 30 | 0-70 | 20 | 0-60 | | | |
| +40 mm | (Fines) | (RDC) | (Fines) | (Lump) | (Fines) | (Lump) | | | |
| 40X30mm | 8-18 | 3-15 | 0 | 13-30 | - | - | | | |
| 20x12mm | 4-9 | 2-42 | 0 | 7-58 | - | - | | | |
| 12x6mm | 5-15 | 1-20 | 7-92 | 4-30 | - | - | | | |
| 6mm | 31-47 | 2-55 | 4-92 | 1-41 | - | - | | | |
| 200 mesh | 11 | - | 5 | - | 9 | - | | | |
| Fuel Ratio | 7.7 | - | 9.0 | - | 7.3 | - | | | |

Table 3. FUEL PROPERTIES OF EXPORT WESTERN COALS USED IN POWER GENERATION

| Coal Source | I | | II | | III | | IV | | V | |
|--|------------|-----------|-----------|-----------|------------|---------|-----------|---------|-----------|---------|
| Process | Export | | Export | | Export | | Export | | Export | |
| | PCC, etc. | | PCC, etc. | | PCC, etc. | | PCC, etc. | | PCC, etc. | |
| Coal Type | Bituminous | | Bitumin. | | Bituminous | | Bitumin. | | Bitumin. | |
| Properties | Typical | Range | Typical | Typical | Range | Typical | Typical | Typical | Typical | Typical |
| (as-received) | | | | | | | | | | |
| Moisture, wt% | 9.4 | 8.4-10.4 | 10.1 | 10.3 | 9.2-11.2 | 7.7 | 9.8 | | | |
| (dry-basis) | | | | | | | | | | |
| Proximate, wt% | | | | | | | | | | |
| VM | 41.1 | 39.5-42.7 | 40.8 | 40.3 | 39.8-41.2 | 41 | 40.2 | | | |
| Ash | 10 | 8.6-10.9 | 9.8 | 9.7 | 8.6-10.8 | 9.2 | 9.9 | | | |
| FC (by diff.) | 48.9 | - | 49.4 | 50 | - | 49.8 | 49.9 | | | |
| Ultimate, wt% | | | | | | | | | | |
| Sulfur | 0.53 | 0.43-0.62 | 0.52 | 0.42 | 0.36-0.52 | 0.5 | 0.6 | | | |
| Carbon | 72.2 | 71.2-72.3 | 72.1 | 72.1 | 71.1-73.7 | 73.3 | 72.3 | | | |
| Hydrogen | 5.4 | 5-5.5 | 5.3 | 5.0 | 4.7-5.2 | 5.5 | 5.2 | | | |
| Nitrogen | 1.33 | 1.15-1.54 | 1.47 | 1.17 | 1.02-1.22 | 1.28 | 1.3 | | | |
| Oxygen (by diff.) | 10.54 | 10.4-12 | 10.81 | 11.61 | 11.4-12.4 | 10.22 | 10.75 | | | |
| Chlorine (ppm) | 150 | 100-300 | 100 | 100 | - | 150 | 120 | | | |
| Mineral of Ash, wt% | | | | | | | | | | |
| Silica | 58.6 | 52.5-61.7 | 56.7 | 52.3 | 50.4-54.1 | 58.6 | 56.1 | | | |
| Alumina | 14.5 | 12-16.5 | 21 | 13.7 | 11.9-14.7 | 14.7 | 11.6 | | | |
| Ferric Oxide | 5 | 2.9-7 | 4.9 | 5.9 | 5.3-6.2 | 4.4 | 5.7 | | | |
| Lime | 10 | 7.7-14 | 5 | 13.1 | 10.7-15.3 | 8.9 | 13.1 | | | |
| Magnesia | 1.8 | 1.6-2.1 | 1.9 | 2.2 | 2-2.5 | 2.4 | 2.4 | | | |
| Sodium Oxide | 1.8 | 0.8-3 | 2.9 | 4.2 | 3.5-4.9 | 1.8 | 3.6 | | | |
| Potassium Oxide | 1.2 | 0.5-1.5 | 1 | 0.4 | 0.2-0.8 | 1.1 | 0.7 | | | |
| Titania | 0.7 | 0.5-0.9 | 0.8 | 0.9 | 0.8-0.9 | 0.7 | 0.8 | | | |
| Manganese Oxide | 0.04 | 0.01-0.05 | 0.03 | 0.04 | 0.03-0.05 | 0.03 | 0.09 | | | |
| Calorific Value | | | | | | | | | | |
| Btu/lb | 12870 | 12750 | 12870 | 12640 | 12580 | 13360 | 12800 | | | |
| HGI | 44 | -12990 | 46 | 43 | -12700 | 44 | 46 | | | |
| Size, wt% | | | | | | | | | | |
| 50 mm x 0 mm | 100 | - | 100 | 100 | - | 96 | 92 | | | |
| 2 mm x 0 mm | 30.3 | - | - | 11.6 | - | 33 | 32.6 | | | |
| Fuel Ratio | 1.2 | - | 1.2 | 1.2 | - | 1.2 | 1.2 | | | |
| Silica Ratio | 0.777 | - | 0.828 | 0.712 | 0.68-0.75 | 0.789 | 0.726 | | | |
| B/A Ratio | 0.268 | 0.18-0.4 | 0.2 | 0.386 | 0.34-0.45 | 0.251 | 0.372 | | | |
| Alkalies (Na2O), wt% | 2.6 | - | 3.6 | 4.5 | 3.5-5.1 | 2.5 | 4.1 | | | |
| 1250, deg F | 2600 | - | 2760 | 2420 | 2400-2475 | 2700 | 2450 | | | |
| Ash Fusion T., deg F (Reduction/Oxidation) | | | | | | | | | | |
| IDT | 2192/2228 | - | 2221 | 2117/2149 | - | 2160 | - | | | |
| ST | 2237/2291 | - | 2320 | 2128/2174 | - | 2250 | - | | | |
| HT | 2300/2354 | - | 2383 | 2179/2220 | - | 2310 | - | | | |
| FT | 2390/2444 | - | 2421 | 2294/2340 | - | 2410 | - | | | |
| Slagging Index | 2147 | 2114-2224 | 2263 | 2114 | 2098-2180 | 2200 | - | | | |
| Fouling Index | 1.8 | 0.8-3 | 2.9 | 4.2 | 3.5-4.9 | 1.8 | 3.6 | | | |

ENVIRONMENTAL ASPECTS OF PRODUCING ELECTRICITY FROM A COAL-FIRED POWER GENERATION SYSTEM - A LIFE CYCLE ASSESSMENT

Pamela L. Spath
Maraget K. Mann
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401

A life cycle assessment (LCA) of different coal-fired boiler systems was performed at the National Renewable Energy Laboratory in collaboration with the Federal Energy Technology Center. Three designs were examined to evaluate the environmental aspects of current and future coal systems. The boundaries of the analysis include all material and energy streams from the following three subsystems: coal mining, transportation, and electricity generation. Upstream processes required for the operation of these three subsystems were included as well as any necessary waste disposal and recycling opportunities. Both surface and underground mining were examined with the coal being transported from the mine to the power plant via rail, a combination of rail and barge, or truck. Additionally, a sensitivity analysis was conducted to determine the parameters that had the largest effects on the conclusions. This paper discusses the results of the life cycle assessment including resource consumption, air and water emissions, wastes, and energy requirements.

INTRODUCTION

Life cycle assessment is a systematic method to identify, evaluate, and help minimize the environmental impacts of a specific process or competing processes. Material and energy balances are used to quantify the resource depletion, emissions, and energy consumption of all processes between transformation of raw materials into useful products and the final disposal of all products and by-products. Three cases were examined for this coal-to-electricity LCA: 1) a plant that represents the average emissions and efficiency of currently operating coal-fired power plants in the U.S. (this tells us about the status quo), 2) a new coal-fired power plant that meets the New Source Performance Standards (NSPS), and 3) a highly advanced coal-fired power plant utilizing a low emission boiler system (LEBS). The overall system consists of coal mining, transportation, and electricity generation. Upstream processes required for the operation of these three subsystems were also included in this study. All three coal systems are fueled with the same type of coal, Illinois No. 6, which will be excavated from mines located in central Illinois. The coal is either surface mined via strip mining or mined by the underground technique of longwall mining. The coal is transported via rail, a combination of rail and barge, or truck. Four different transportation cases were evaluated for this assessment: average user by land, average user by river, farthest user, and mine mouth. Other materials such as chemicals and wastes are transported via truck and rail. The information about the methodology and the results contained in this paper are taken from a larger, more detailed report (Spath and Mann, 1998).

AVERAGE PLANT

The average coal power plant consists of the following main equipment/process steps: pulverized coal boiler, baghouse filter, conventional limestone flue gas clean-up (FGC) system, heat recovery steam generator (HRSG), and steam turbine. The emissions for this case represent the average emissions from all U.S. coal-fired power plants in 1995. These were calculated by dividing the total coal-generated U.S. emissions of a particular pollutant on a weight basis (kg) by the total electricity generated (kWh) from coal in the U.S. To maintain a mass balance around the power plant, a specific plant with emissions similar to the calculated averages and which is feeding the designated type of coal for this LCA was identified. The actual resource requirements, final emissions, and energy consumption from this specific plant were used to represent the average power plant in this study.

NSPS PLANT

Emissions for this case are calculated based on flue gas clean-up removal efficiencies such that the power plant meets the New Source Performance Standards (NSPS). The following are the standards of performance in g/GJ heat input on a higher heating value basis, with lb/MMBtu in parenthesis, for new electric utility steam generating units using bituminous coal: NO_x = 260 (0.60), SO_x = 258 (0.60), and particulates = 13 (0.03). These values were taken from the Code of Federal Regulations, 40 CFR 60.42a, 60.43a, and 60.44a; new plants built after 1978 are required to meet these standards. Except for higher pollutant removal efficiencies achieved through boiler modifications and more advanced clean-up technologies, the process configuration for this case is the same as that for the average plant.

LEBS PLANT

Emissions for this case are those forecasted from a future plant utilizing a Low Emission Boiler System (LEBS). LEBS is projected to have significantly higher thermal efficiency, better performance, and a lower cost of electricity than current coal-fired power plants. The technology being considered in this assessment is by the developer DB Riley Inc., and is being researched under the Department of Energy's sponsorship. The objective of the LEBS program is to produce technologies that result in lower emissions such that the NO_x and SO_x emissions are 1/6 of the NSPS and the particulate emissions are 1/3 of the NSPS. The DB Riley technology uses a low-NO_x system with advanced burners, air staging, and a wet ash slagging system. The copper oxide flue gas clean-up process utilizes a regenerable sorbent, removing both SO₂ and NO_x from the flue gas and producing sulfuric acid or sulfur as a by-product instead of producing a solid waste. The sorbent is regenerated using natural gas as the reducing agent.

COAL MINING

For this study, both strip mining and underground longwall mining were examined. The resources, emissions, and energy use associated with the excavation of the coal were included in this LCA. The processes studied include raw material extraction, equipment manufacture, coal mining, coal preparation/cleaning, all necessary transportation of chemicals, etc., and all necessary upstream processes. The resources, energy, and emissions associated with the mining equipment are based on the types of machinery used for each coal excavation process, the fuel requirements, and the lifetime of the machinery. Additionally, the process steps involved in land reclamation are included in the surface mining option. Overall, the environmental impacts from surface versus underground mining are not significantly different in any of the three power plant cases examined (average, NSPS, and LEBS). The main difference between these two mining techniques is that the surface mining subsystem results in a higher amount of airborne ammonia emissions due to the production of ammonium nitrate explosives which are used at the mine. Another important difference is that underground mining requires limestone which emits a large amount of particulates during its production. Therefore, results in this paper are presented for the surface mining cases only.

COAL TRANSPORTATION CASES

The inventory assessment for the transportation subsystem includes the energy required and emissions generated for the transportation of coal by barge, train, or truck between the boundaries of the coal mining and power generation subsystems. The resources, energy, and emissions related to extracting crude oil, distilling it, producing a usable transportation fuel, and distributing it to refueling stations plus the emissions produced during combustion of the fuel were included in the total inventory. The material requirements for each of the various modes of transportation were used in determining the resources, energy, and emissions associated with vehicle production and decommissioning.

The following four transportation cases were examined for this study: (1) average user by land: railcar = 483 km, (2) average user by river: railcar = 48 km plus barge = 435 km, (3) farthest user: railcar = 1,538 km plus barge = 504 km, and (4) mine mouth: minimal truck transport = 2 km. The average user by land was determined based on the fact that most of the utilities serviced from the Perry County region fall within the distance of 483 km, which is the rail distance from E. St. Louis to Chicago. This distance also includes at least parts of the states of Illinois, Wisconsin, Iowa, Indiana, Kentucky, Alabama, Mississippi, and Missouri. When considering barge transport, the coal must first be hauled 48 km by rail to the Mississippi River before being loaded onto a coal barge. The barge distance of 435 km listed above for the average user by river case reaches up the Mississippi River to Iowa or down the river to the state of Mississippi and could include traffic up the Ohio River. The farthest user consists of rail transport to the Mississippi River (48 km) then river transport to Memphis, Tennessee (504 km) and finally rail transport to central Florida (1,490 km). The transferring of coal between rail and barge was not included but should be minimal compared to the actual transportation of the coal.

RESULTS: RESOURCE REQUIREMENTS

Fossil fuels, metals, and minerals are used in all of the processes steps required to convert coal to electricity. In terms of resource depletion, coal is used at the highest rate. For the average and NSPS cases, limestone and oil account for the majority of the remaining resources consumed compared to the LEBS case, where the bulk of the remaining resource consumption is natural gas and oil. Table 1 shows the majority of the resources used for each coal case studied.

Table 1: Resource Consumption

| Resource | Average | | NSPS | | LEBS | |
|-------------|-------------|--------|-------------|--------|-------------|--------|
| | % by | g/kWh | % by | g/kWh | % by | g/kWh |
| Coal | 80.4 | 474.44 | 78.0 | 433.84 | 97.3 | 352.49 |
| Limestone | 17.4 | 102.84 | 19.7 | 109.49 | 0.0 | 0.04 |
| Oil | 1.9 | 11.48 | 2.0 | 11.32 | 1.3 | 4.88 |
| Natural gas | 0.2 | 1.25 | 0.2 | 1.26 | 1.3 | 4.53 |

- (a) Numbers are reported for the surface mining case. However, the underground mining numbers are similar to those listed above.
- (b) Transportation = average user by river.
- (c) Percent of total resource consumption. Not all resources consumed by the system are shown; therefore the numbers do not add up to 100%.
- (d) Resource consumption per kWh of net electricity produced averaged over the life of the system.

RESULTS: AIR EMISSIONS

In terms of total air emissions, CO₂ is emitted in the greatest quantity accounting for 98-99 wt% of the total air emissions for all cases examined. The following are the total CO₂ emissions for the average, NSPS, and LEBS case: 1,022 g/kWh, 941 g/kWh, and 741 g/kWh of net electricity produced. The majority of the CO₂, greater than 95%, is emitted from the power plant subsystem during operation of the coal-fired plant. As shown in Table 2, the next highest air emissions include particulates, SO_x, NO_x, CH₄, CO, and NMHCs. In all three coal cases the power plant produces most of the SO_x, NO_x, and CO while the methane comes primarily from the coal mine. For the average and NSPS case, the majority of the particulates come from the production of limestone. For the LEBS case, the majority of the particulates are emitted by the power plant during normal operation and the second major source of particulates is copper oxide production. For all three cases, the NMHC emissions are evenly distributed among the mining, transportation, and power plant subsystems. However, for the LEBS case it should be noted that a significant amount of the total NMHC emissions are emitted during natural gas production.

Table 2: Air Emissions (Excluding CO₂)

| Air | Average | | NSPS | | LEBS | |
|-----------------|-------------|-------|-------------|-------|-------------|-------|
| | % by | g/kWh | % by | g/kWh | % by | g/kWh |
| Particulates | 44.3 | 9.21 | 61.0 | 9.78 | 4.4 | 0.11 |
| SO _x | 32.2 | 6.70 | 15.7 | 2.53 | 28.0 | 0.72 |
| NO _x | 16.1 | 3.35 | 14.6 | 2.34 | 21.3 | 0.54 |
| CH ₄ | 4.4 | 0.91 | 5.2 | 0.84 | 27.9 | 0.75 |
| CO | 1.3 | 0.27 | 1.5 | 0.25 | 7.5 | 0.19 |
| NMHCs (e) | 1.0 | 0.21 | 1.3 | 0.20 | 7.5 | 0.19 |

- (a) Numbers are reported for the surface mining case. However, the underground mining numbers are similar to those listed above.
- (b) Transportation = average user by river.
- (c) Percent of total air emissions *excluding* CO₂ emissions. Not all resources consumed by the system are shown; therefore the numbers do not add up to 100%.
- (d) Air emissions per kWh of net electricity produced averaged over the life of the system.
- (e) NMHCs = non-methane hydrocarbons including volatile organic compounds (VOCs).

RESULTS: WATER EMISSIONS AND WASTES

For all three coal cases, the majority of the water emissions from the system occurred in the mining and power plant subsystems. The water emissions were evenly distributed between these two subsystems. In general, though, the total amount of water pollutants was found to be small compared to other emissions.

A large amount of the solid waste in the average and NSPS cases comes from the power plant in the form of flue gas clean-up waste and ash that must be landfilled, 58-61% and 20-23% of the total waste, respectively. For these two cases, non-hazardous solid waste accounts for the balance of the total waste and the majority of this waste is generated during limestone production. The flue gas clean-up process for the LEBS case utilizes a regenerable sorbent, therefore, the bulk of the waste

from this system is ash which accounts for 87-93% of the total waste. The remaining waste for the LEBS case is non-hazardous solid waste which primarily comes from the mining operations.

RESULTS: ENERGY

The energy use within the system was tracked so that the net energy production could be assessed. Several types of efficiencies can be defined to study the energy budget of the coal system. The first being the power plant efficiency defined in the traditional sense as the energy delivered to the grid divided by the energy in the feedstock to the power plant (coal and natural gas in the LEBS case). Four other types of efficiencies can be defined as follows:

Table 3: Energy Efficiency and Ratio Definitions

| Life cycle efficiency (%) (a) | External energy efficiency (%) (b) | Net energy ratio (c) | External energy ratio (d) |
|---|------------------------------------|-------------------------|------------------------------|
| $\frac{Eg - Eu - Ec - En}{Ec + En}$ | $\frac{Eg - Eu}{Ec + En}$ | $\frac{Eg}{Eff}$ | $\frac{Eg}{Eff - Ec - En}$ |
| where: Eg = electric energy delivered to the utility grid Eu = energy consumed by all upstream processes required to operate power plant Ec = energy contained in the coal fed to the power plant En = energy contained in the natural gas fed to the power plant (LEBS case only) Eff = fossil fuel energy consumed within the system (e) | | | |

- (a) Includes the energy consumed by all of the processes.
- (b) Excludes the heating value of the coal and natural gas feedstock from the life cycle efficiency formula.
- (c) Illustrates how much energy is produced for each unit of fossil fuel energy consumed.
- (d) Excludes the energy of the coal and natural gas to the power plant.
- (e) Includes the coal and natural gas fed to the power plant since these resources are consumed within the boundaries of the system.

The net energy ratio is a more significant measure of the net energy yield from the system than the external energy ratio because it accounts for all of the fossil energy inputs. The following table contains the resulting efficiencies and energy ratios for each coal case.

Table 4: Efficiencies and Energy Ratio Results

| Case (1*, 2*) | Power plant efficiency (%) (3*) | Life cycle efficiency (%) (3*) | External energy efficiency (%) (3*) | Net energy ratio | External energy ratio |
|------------------|---------------------------------------|--------------------------------------|---|------------------------|--------------------------|
| Average | 32 | -76 | 24 | 0.29 | 5.0 |
| NSPS | 35 | -73 | 27 | 0.31 | 5.1 |
| LEBS | 42 | -66 | 34 | 0.38 | 6.7 |

- (a) Coal LCA numbers are reported for the surface mining case. However, the underground mining numbers are similar to those listed above.
- (b) Transportation = average user by river
- (c) Efficiencies are on a higher heating value basis.

One of the most surprising results of this study was that upstream processes consumed such great quantities of energy. Intuitively obvious is the fact that because the power plant efficiency is less than one, the net energy ratio, which includes the energy in the coal consumed by the power plant, will be a fractional value. However, in subtracting out the energy of the coal feed in the external energy ratio, one would expect the results to be much higher than they are. However, in the average and NSPS cases, limestone production was found to require a significant amount of energy; in the LEBS case, excluding the coal feed, the majority of the total energy is used in natural gas production. Limestone production accounts for 25% and 28% of the total system energy consumption for the average and NSPS cases, respectively, and for the LEBS case natural gas production accounts for 37% of the total system energy consumption.

For all three cases examined (average, NSPS, and LEBS), a large amount of energy was also consumed by the transportation subsystem (except for the mine mouth case), primarily from the energy required to extract crude oil, distill it, produce a usable transportation fuel, and distribute it to refueling stations. The following percentages are for surface mining and transportation via the average user by river case. For all three power plant cases the energy consumption for the fuel required to transport the coal by a combination of train and barge accounts for 30-33% of the total system energy consumption.

SENSITIVITY ANALYSIS

A sensitivity analysis was conducted to determine the parameters that had the largest effects on the results and to determine the impact of estimated data as well as variations in data on the conclusions. The following variables had the largest effect on resource consumption, emissions, and energy usage: reducing the power plant construction materials, changing the power plant operating capacity factor, and increasing or decreasing the transportation distance. Varying the amount of mining methane emissions had a large impact on the overall methane emissions from the system, however, this variable will be site-specific and ultimately should be examined on a case by case basis. Changing the power plant efficiency or changing the coal transport distance are the only variables that had a noticeable effect on the efficiency and energy ratio results. In all sensitivity cases tested, however, the net energy ratio varied by only small amounts, mostly due to the energy in the coal feed, the energy consumed in limestone and natural gas production, and the energy used in transportation. For the average, NSPS, and LEBS cases, the net energy ratios range from 0.24 - 0.33, 0.27 - 0.36, and 0.33 - 0.42, respectively.

CONCLUSIONS

Overall, the environmental impacts from surface versus underground mining are not significantly different in any of the three power plant cases examined (average, NSPS, and LEBS). As expected, the majority of the overall methane emissions come from the mine itself. However, as stated above these emissions are site-specific and ultimately should be evaluated on a case by case basis. Additionally, about half of the system's water emissions come from the mining subsystem.

For the average and NSPS cases a large amount of the total energy requirement for the power generation subsystem comes from limestone production whereas for the LEBS case the majority of the total energy is required for natural gas production. Therefore, even with increased power plant efficiency, the overall system energy balance of coal-fired power plants will not increase significantly unless technologies can be developed to reduce upstream energy consumption.

Of the three subsystems examined (coal mining, transportation, and electricity generation), transportation required the least amount of resources and had the lowest air, water, and solid waste emissions even when considering the farthest user case. However, the energy consumption for this subsystem was significant (excluding the mine mouth case). As anticipated, for mine mouth operation, all resource consumption, emissions, and energy usage are a small percentage of the total over the life of the system. For the other three transportation cases (average user by river, average user by land, and farthest user) oil consumption as well as a few air and water emissions are high. It was found that the transportation distance has a significant effect on the oil consumption, a few of the system's emissions, and the energy consumption whereas the mode of transportation has virtually no effect on the results.

In all three coal cases the power plant produces the majority of the SO_2 , NO_x , and CO . Also, half of the water emissions occurred in the power plant subsystem. Most of the solid waste in the average and NSPS cases comes from the power plant in the form of flue gas clean-up waste that must be landfilled. For these two cases there is also a high percentage of ash which is landfilled and limestone production produces a considerable amount of non-hazardous solid waste. The flue gas clean-up process for the LEBS case utilizes a regenerable sorbent, therefore, the primary waste from this system is ash. As expected, the LEBS plant requires fewer resources and energy and produces fewer emissions and waste per unit of energy delivered to the utility grid than the average or NSPS cases. The life cycle efficiency, external energy efficiency, net energy ratio, and external energy ratio are similar for the average and NSPS plant. The energy efficiency and ratio numbers are all somewhat higher for the LEBS.

FUTURE WORK

The primary goal of this life cycle assessment was to assess the environmental aspects of producing electricity from a coal-fired power system. The focus of this initial work was on an inventory of all resources, environmental emissions, and energy flows of the system, studied in a cradle-to-grave manner. Therefore, a comparative analysis was not performed at this time. Ultimately, the resulting emissions, resource consumption, and energy requirements of this system will be compared to a previously completed LCA of electricity production from a biomass gasification combined-cycle (BIGCC) power plant (Mann and Spath, 1997) and a study currently being conducted which involves co-firing biomass in a coal-fired boiler.

REFERENCES

1. P.L. Spath and M.K. Mann. (1998) "Life Cycle Assessment of Coal-fired Power Production," National Renewable Energy Laboratory, Golden, CO. TP-570-25119.
2. Office of the Federal Register National Archives and Records Administration. (1996) *Code of Federal Regulations. Protection of Environment*. Title 40. Part 60, July.
3. M.K. Mann and P.L. Spath. (1997) "Life Cycle Assessment of a Biomass Gasification Combined-Cycle Power System," National Renewable Energy Laboratory, Golden, CO. TP-430-23076.

ECONOMIC PLANT PRODUCING TRANSPORTATION FUELS & FEED FOR CARBON PRODUCTS FROM COAL

Theodore B. Simpson
U.S. Dept. Of Energy, Fossil Energy Division, Office of Coal Fuels and Industrial Systems
Washington, D.C. 20585

INTRODUCTION

The U.S. needs a stable supply of environmentally clean, affordable fuels. After the oil embargo and gasoline shortage of the early 1970's when oil reached a price of \$35/bbl, the U.S. Dept of Energy (DOE) intensified its work on making transportation fuels by the direct liquefaction of coal, which is the most abundant energy source in the U.S. Continuing improvement in this technology has resulted in confidence in the advanced technology developed on a small scale (to 3TPD.) This evolutionary development ran from bench scale and the Cresap, PA, donor solvent pilot plant in the '70's to the Ft. Lewis, WA, Solvent Refined Coal pilot plant and the Wilsonville, AL, 3TPD process demonstration unit (PDU) in the late 1970's to the demonstration plant program (approximately 200 TPD) in the early 1980's. Thereafter, Exxon offered commercial licenses without any takers, and the program slowed down to further bench-scale and PDU tests at Wilsonville and its successor, Hydrocarbon Technologies, Inc (NJ.)

Further scale-up remains needed, however, to establish commercial readiness. But, partly as a result of improved techniques for exploration for petroleum, world reserves have expanded, mostly in developing nations whose economic needs have pushed marketing and driven oil prices down to about \$14/bbl. Nonetheless, Table 1^(a) shows that projections are that not only will oil prices increase, but also supply will start to decline starting at about the year 2020 while demand will steadily increase. This would lead in the absence of new factors to an inevitable rapid increase in price. If a partial solution is found in the conversion of coal, Table 1 shows that an expected decline in the cost of coal should be a mitigating factor.

APPROACH

The present price of about \$14/bbl is a much more difficult target for liquids from coal. This has led DOE to look for profitable co-products to improve the economics of the liquefaction process. A particularly attractive one of these is a heavy, clean hydrocarbon pitch suitable as feed to make carbon products. In addition to such million-tons/yr markets for carbon products as anode coke for the aluminum industry and graphite anodes, there is the rapidly growing need for feed for manufacturing Carbon Fibers for use in composite materials. These carbon fibers and composites thereof have an unusual combination of superior strength and light weight. As a consequence this is likely to lead to their becoming commodity materials used for structural members and bodies for high mileage cars. This in turn could result in a dramatic reduction in emissions from vehicles as well as a significant decrease in the cost of their fabrication. Another desirable outcome is that the carbon products produced tie up carbon for an extended period and reduce the emissions of the Greenhouse Gas, CO₂, that would result if the product were fuel.

This paper describes a proposed giant step in process development/demonstration based on data developed in the 1980's by DOE with the 3 TPD Wilsonville, AL, coal liquefaction PDU (b.) Liquefying coal requires its dissolution, liquefaction at ~825F and 2000 psi hydrogen pressure, plus deashing either by filtration or critical solvent deashing, and further selective hydrotreating to produce light hydrocarbons without over cracking them. With the carbon-product pitch as a valuable co-product obtained as a bottom of the barrel product of the first of the two stages, further selective hydrocracking of this co-product is no longer required so that the complexity of the process and its severity and hydrogen requirement are significantly decreased. Figure 1 compares the two process variants. Instead of two expensive slurry bed catalytic stages and ash separation as presently specified to produce an all distillate product, a thermal reaction stage, ash separation and a fixed catalytic stage suffice. Fixed bed catalysis has been estimated to cost one-fifth of the cost of ebullated bed catalytic reactors. With removal of the first stage heavy fraction as a source of the Carbon Product feed, the cost of the second stage fixed bed catalytic reactor will be smaller and cheaper. As a result the process economics are estimated to be significantly improved.

DATA

Table 2 compares the conditions selected for the 1982 one product configuration vs. the proposed co-product plant. As stated the primary source of cost reduction is reduction in the amount and hence cost of hydrogen. In the present one product, "all distillate" plant, the hydrogen cost has been estimated to be one-half of the total cost of the conversion of coal to distillate hydrocarbon fuels or

\$15/bbl of product. Table 3 lists the ways in which hydrogen requirement is reduced. The lower severity (temperature, pressure, residence time) results in a drop in C1-C4 gaseous hydrocarbons which require much hydrogen but have little more than fuel value. The decrease is estimated to be from 7% to 3% on feed coal with an average composition of CH₃ giving a 1.65% drop in total H₂ needed. Moreover, for a process requiring a total residence time of one hour or more, its reduction to reduce severity would help. This should work since the PDU testing included a successful short contact time thermal stage of a few minutes. A more significant decrease in hydrogen requirement results from the conversion of the feed coal with its average composition of CH_{0.7} to essentially pure carbon at about 800C which otherwise would need an added 1.2 atoms of H to convert them to liquids. This 1.9 H/C savings cuts the hydrogen cost by \$10.50 and the product cost to \$20/bbl of fuel plus carbon product carbon equal to that in one bbl of fuel which assumes that the carbon has the same value as the oil. Therefore, it was assumed that Carbon products will be 40% of the product slate. The hydrogen formerly found in the coal is recovered when it reports upon the conversion to Carbon Products largely as aromatic distillates that are suitable as part of the fuels product or as chemical products.

DISCUSSION

A reasonable approximation is that the revenue requirements of a co-products plant is the same as the one-product plant. For the one-product plant the revenue requirement equals the typical 4 Bbl/Ton of feed coal at the above reduced price of \$20/Bbl made possible by making 0.4 Tons of C-Products/Ton of feed coal giving \$80/Ton of feed coal as the required revenue per ton of feed coal. Table 4 gives possible options for pricing of the two co-products that each generate the needed revenue. This shows that the oil product can be priced competitively even with the existing world petroleum prices of \$10-14/bbl with the last set of co-product prices shown. The Carbon Product feed price is also realistic since Table 4 shows that with the oil product priced at \$10/bbl the required price of C-Product feed is \$140/ton of Carbon Product (\$0.07/lb.) vs. a carbon fiber manufacturer's estimate that his feed cost is \$1.80/lb. for carbon fibers. Table 4 also shows the ability to exercise pricing flexibility, i.e. the capability of the processor to follow the ups and downs in world petroleum prices in order to maximize profitability even as is the case in the pricing of gasoline by the petroleum industry. This compares with \$30/bbl oil needed for a single product plant at a 20% ROI. No credit has been taken for the simpler process and reduction in process severity.

CONCLUSIONS

Added R&D will be needed (1) to redefine the conditions required for the two product plant though no dramatic changes are indicated, (2) to demonstrate the integrated process for valuable co-products, (3) to confirm the economics, and (4) to confirm marketing estimates. Ongoing tests by a DOE contractor (CCP) will continue in order to confirm the suitability of the carbon product feeds and carbon products produced. Carbon fiber composites are already common for tennis rackets, for golf clubs, and for aircraft parts. Work on production and marketing of carbon products for automobile and structural applications will be needed. A life cycle study has been reported^(c) of the use of carbon product composites for automobile manufacture taking into account ease of fabrication, fuel economy, etc to determine the price of carbon fibers at which their use for this application is justified. The study concludes that this price is \$5 to \$7.50/lb. A major manufacturer has indicated that it already prices carbon fibers at \$8/lb. to large users and expects to achieve \$5/lb. in the year 2000.

If the proposed added work confirms the above conclusions as to supply-demand for fuels, competitive position of carbon fiber composites for high volume markets, and capability of direct coal liquefaction to supply low cost carbon product feed, a number of important, significant improvements should result. In transportation, use of light weight vehicles manufactured from carbon fiber composites having reduced emissions and lower operating cost will grow. In the fuels area, the coal liquefaction co-product plants will add to domestic fuel resources and create domestic jobs that otherwise would continue their decline. With respect to the future of U.S. coal such co-product plants will speed up utilization of this large domestic energy resource in an environmentally safe manner.

REFERENCES

- (a) U.S. D.O.E. and/or contractor estimates, 1997,1998.
- (b) U.S.D.O.E. Report DOE/PC/50041-55, Sept, 1985.
- (c) A.E.Mascarin & M.M.Brylawski, http://www.rmi.org/hypercars/b_i_w/T95_35.html, 1998

**Table 1: PROJECTED RESOURCE BASE CONSUMPTION
AND PRICE OF ENERGY
THROUGH 2020⁽¹⁾ AND BEYOND⁽²⁾**

| | 1996 | 2000 | 2005 | 2010 | 2015 | 2020 | 2040 | 2060 |
|----------------------------------|-------|-------|-------|-------|-------|-------|------|------|
| U.S. Consumption, B/D | 18.44 | 19.62 | 21.15 | 22.70 | 23.65 | 24.39 | ---- | ---- |
| Oil Price, \$/B | 20.48 | 19.11 | 20.19 | 20.81 | 21.48 | 22.32 | ---- | ---- |
| Coal Price, \$/Ton | 27.52 | 25.80 | 24.40 | 23.12 | 21.76 | 20.56 | ---- | ---- |
| World Product Capability, B/D | 75.0 | 81.0 | 87.0 | 93.0 | 98.0 | 100.0 | 55.0 | 12.0 |

- (1) DOE Energy Information Agency (1998)
(2) DOE Energy Information Agency, as supported by Mitretek (1998)

**TABLE 2: CURRENT AND 1982 SINGLE PRODUCT PLANTS
VS 1982 CO-PRODUCT PLANTS
(All %'s based on feed coal)**

| Type Plant: | | 1982 Single Prod.344b-g | 1982 Single Prod., Short Contact,242 | Calc'd 1982 Co-prod, Short Contact Time | Current Single Dist. Prod. |
|----------------|------------------------------|----------------------------|--|---|----------------------------------|
| | <u>Proc Stage 1</u> | | | | |
| | Reactor Size | 8 | 2 | 2 | 8 |
| | Space Rate, lb/hr,sq ft | 40 | 95 | 95 | 40 |
| | Pressure, psi | 2400 | 2400 | 2400 | 2400 |
| | Temperature, F | 825 | 825 | 810 | 825 |
| | Hydrogen Used, % | 1.5 | 0.7 | 0.7 | 3. |
| | C1/C3 Gas Make,% | 4.2 | 3.3 | 2.0 | 4.5 |
| | % C-Prod. Feed or % Resid | 5 resid | 5 resid | 55 | 5 resid |
| | Distillables, % | 55 | 28 | 20 | 58 |
| | | | | | |
| | <u>Entire Process</u> | | | | |
| | Hydrogen Used, % | 5 | 5 | 2.3 | 7 |
| | C1/C4 Gas Make, % | 7 | 5 | 3 | 7 |

TABLE 3: WAYS IN WHICH HYDROGEN REQUIREMENT IS REDUCED
(All %'s are % of Feed Coal)

| Means of Reducing H2 Requirement | H2 Requirement, Current Single Product Plant | H2 Requirement, Proposed Two Product Plant | Estimated Savings: % H2 on Coal & \$/Bbl Equiv. |
|---|--|--|---|
| Reduced "CH3" Gas Make | 7.0% | 3.0% | 0.8% & \$1.65/Bbl |
| H2 Released by "CH.7" Coal Converted to C-Products | 0 | 1.9% | 1.9% & \$3.20/Bbl |
| Avoid 1.2 H/C Needed to Convert Above Coal to "CH2" Distillates | 0 | 2.8% | 2.8% & \$6.00/Bbl |
| TOTAL SAVINGS | | | \$10.60/Bbl |

Basis:

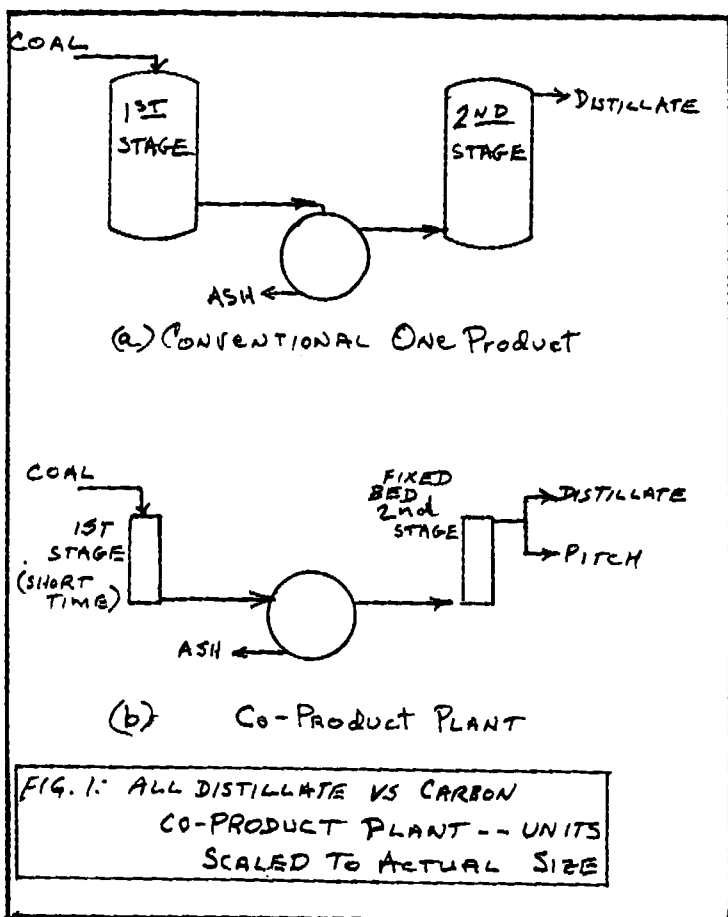
- (1) Upon the high temperature version of C-Products feed to carbon products essentially all the hydrogen reports as volatized hydro aromatic distillate product.
- (2) Estimated 40% of Feed Coal to C-Product Feed

TABLE 4: RESULTANT CO-PRODUCT COSTS

CASE I: MAKE 0.4T. C-PRODUCT+ (0.6)(4 BBL/T) OIL PER TON OF FEED COAL
ASSUME TOTAL PROCESS COST = (\$30 - \$10 SAVINGS)(4 BBL/T COAL)

| Assumed Price of Heavy Oil for C-Product, \$/T. C-Product | Resultant Product Oil Cost \$/Bbl |
|---|-----------------------------------|
| 100 | 16.7 |
| 50 | 25.0 |
| 75 | 21.0 |
| 140 | 10.0 |

Basis: 0.4 T. C-Prod + 2.4 Bbl Oil
 T. Coal Feed



ASSESSING CONDENSED AROMATIC COAL MATERIALS AS PRECURSORS FOR HIGH-VALUE CARBON PRODUCTS

M. Mercedes Maroto-Valer¹, Darrell N. Taulbee² and Harold H. Schobert¹

¹The Energy Institute, The Pennsylvania State University, 405 Academic Activities Bldg, University Park, PA-16802. ²University of Kentucky - Center for Applied Energy Research, 2540 Research Park Drive, Lexington KY 40511

Keywords: unburned carbon, anthracite, activated carbons.

The increasing role of coal as a source of energy in the 21st century will demand environmental and cost-effective strategies for the use of carbonaceous waste products from coal combustion. Accordingly, this paper demonstrates the ability of unburned carbon from coal combustion waste to generate activated carbons by steam activation. Non-fuel uses of coal will also become more important in the coal industry of the next century. In particular, significant growth potential exists for the production of adsorbent carbons with molecular sieve properties. Anthracites can easily be tailored for this specific purpose due to their inherent fine structure.

INTRODUCTION

The US electric power industry relies heavily on the use of coal as the primary energy source. In 1997, around 90% of the total US coal production was used in coal-fired units to generate over 55% of the total electricity¹. Furthermore, coal is the most abundant fossil fuel resource in the US, and therefore it will even play an increasing role as a source of energy in the 21st century². However, the use of coal for energy generation faces environmental challenges due to the emissions of pollutants such as NO_x and SO_x by coal combustion furnaces. Moreover, environmental pressures will only intensify in the next century and to guarantee a key role of coal as energy source, the conventional processes for coal utilization have to be redesigned to comply with clean air regulations. In particular, the implementation of these regulations concerning NO_x emissions is being addressed in coal combustion furnaces mainly by a combination of low-NO_x burners and catalytic reduction systems. Although low-NO_x burner technologies efficiently decrease the emissions level by lowering the temperature of combustion, they also reduce the combustion efficiency, with a corresponding alarming rise in carbonaceous waste product from coal combustion³. In 1997, the combustion of 830 million tonnes of coal generated around 75 million tonnes of coal combustion by-products (CCBPs), mainly fly ash containing unburned carbon⁴. Due to the present lack of routes for their effective use, the fate of these products is mainly disposal. However, the increasingly severe regulations on disposal and the limited access to new disposal sites with the subsequent increase in the cost of disposal, will force the coal and energy industry to recycle a larger amount of CCBPs. Consequently, there is a clear need to establish environmental and cost-effective strategies for the use of these carbonaceous waste products from coal combustion.

The carbonaceous residue in fly ash, unburned carbon, is a potential precursor for the production of adsorbent carbons, since it has gone through a devolatilization process while in the combustor, and therefore, only requires to be activated. However, for new precursors to compete effectively with the conventional raw materials like wood, they must have a low cost, low mineral matter content and easily be converted into activated carbons⁵. The unburned carbon in the ash furnishes satisfactorily all these conditions, since it can readily be obtained from the utility industries as a by-product, it can be beneficiated

from the fly ash by commercially available techniques and it has already gone through a devolatilization process in the combustor and, therefore, only requires to be activated. However, no attempt to activate this carbonaceous waste has been conducted thus far.

In addition to the major use of coal as a fuel source, non-fuel uses like production of high-value chemicals and premium carbon products, will also become more important in the coal industry of the next century². Significant growth potential exists for the use of coal as precursor for the production of activated carbons, due to the continuous worldwide growing demand for adsorbent materials. The main reason for this expanding market is the ubiquitous use of activated carbons as adsorbent materials in a broad range of increasing household, medical, industrial, military and scientific applications, that range from gas-phase adsorption in household air conditioning equipment and industrial emissions control, to liquid-phase adsorption for water treatment and even gold recovery. Each application is associated with a specific set of properties of the activated carbon, and precursors that can easily be converted into the required adsorbent materials will excel. This is the case of anthracites, since their fine pore structure makes them excellent raw materials for the production of adsorbent carbons with molecular sieve properties for gas separation in pollution control technologies⁶. However, the use of anthracites as precursors for adsorbent materials is being under-exploited, probably due to the limited number of studies assessing the possible routes for their conversion into activated carbons.

This work addresses the potential use of both unburned carbon from coal combustion and anthracites as precursors for adsorbent carbons. Both materials have highly condensed aromatic structures with a low volatile content. A single step carbonization/activation process was used for the activation of these materials, using steam as the activating agent. The porosity of the resultant activated carbons was characterized by conducting N₂ isotherms at 77K.

EXPERIMENTAL PROCEDURE

Samples A fly ash containing unburned carbon was collected from the mechanical precipitators of unit #3 (70 MW) of the Dale power plant (Eastern Kentucky Power). The sample was screened with a 140 mesh sieve (106 μm), with the 140+ fraction being triboelectrostatically separated to obtain a carbon-enriched sample with a glass content of $\sim 10\%$ volume, as determined by petrography³. A detailed description of this unburned carbon sample (UC) is given elsewhere³. The Pennsylvania anthracite (A) selected for this study contains 6.8 % ash (db) and the atomic H/C ratio is ~ 0.19 . Previous studies conducted by the authors have shown that the particle size of the starting anthracite was the most critical variable that affects the properties of the resultant adsorbent carbon. Accordingly, for this study the anthracite was ground and sieved to obtain a particle size fraction 250-150 μm .

Activation procedure The activation of the samples was carried out in an activation furnace, that consists of a stainless steel tube reactor and a vertical tube furnace, similar to the one used previously by the authors⁶. Small modifications were made in the previous design to improve the flow of steam throughout the reactor and to be able to work with a significant smaller particle size. Typically 3 - 5 g of sample was held isothermally at 850° for periods of 60 (UC-60 and A-60) and 90 (A-90) minutes while flowing steam. A reservoir was used to pump water into the reactor at low flowrates by introducing a slight head pressure of nitrogen. The flowrates used were 0.3 and 1.2 g of water/min for the unburned carbon and anthracite, respectively.

Porosity measurements N₂ adsorption isotherms at 77K were conducted in Quantachrome adsorption apparatus, Autosorb-1 Model ASIT. The BET surface areas (SA) were calculated using the adsorption points at the partial pressures 0.1

- 0.3. For the activated samples, the total pore volume, V_{TOT} , was calculated from the amount of vapor adsorbed at partial pressure 0.95.

RESULTS AND DISCUSSION

Inherent porosity of the raw materials Figure 1 shows the N_2 -77K adsorption isotherms for the raw unburned carbon (UC) and anthracite (A) and illustrates the different inherent porosity of these materials. The adsorption isotherm of the unburned carbon (UC) sample is a Type II isotherm according to the classification of Brunauer, Deming, Deming and Teller (BDDT) ⁷. This Type II isotherm is typical for nonporous or macroporous adsorbents, on which unrestricted monolayer-multilayer adsorption can occur, and the inflexion point of the isotherm indicates completion of monolayer and the onset of multilayer coverage. Pore size distribution studies have shown that the porosity of this UC sample is mainly due to meso- and macropores, with pore widths typically over 40 nm. In contrast, the adsorption isotherm of the anthracite (A) is Type I (Figure 1), corresponding to a microporous system, as expected due to the well-known fine structure of anthracites. However, this isotherm also presents a tail as saturation pressure is approached, indicating the presence of some macropores.

Table 1 lists the BET surface areas (SA) for the precursors. The unburned carbon sample has a SA of 40 m²/g, compared to only <1 m²/g for the anthracite. The reason for the higher SA of the unburned carbon is probably due to the generation of porosity by the combustion process. The extensive and rapid devolatilization that coal undergoes in the combustor, seems to promote the generation of meso- and macropores.

Development of activated carbons from unburned carbon and anthracite All the samples were activated at 850°C for periods of 60 (UC-60 and A-60) and 90 (A-90) minutes. Table 1 lists the solid yields of the activated samples. As expected, when comparing samples with the same activation time, UC-60 and A-60, the UC presents a much higher solid yield than the anthracite, 73 % vs. 59 %, since the UC has already gone through a devolatilization process in the combustor. In fact, elemental analyses conducted in the raw UC have reported an atomic H/C ratio as low as 0.02, indicating the very low content of volatiles and the high degree of condensation of this sample. This makes the UC an attractive precursor for the production of activated carbons, since it presents much higher solid yields than conventional precursors, like wood (volatile content ~ 60%).

Figure 2 shows the N_2 -77K adsorption isotherms for the steam activated unburned carbon (UC-60) and anthracites (A-60 and A-90). The three isotherms, regardless of the precursor, are Type I, with the typical concave shape to the P/P_0 axis and approaching a limiting value as the saturation pressure is reached. Although the isotherm of the activated carbon produced from the unburned carbon sample, UC-60, is still Type I, the isotherm does not reach a plateau for high relative pressures. Therefore, although UC-60 has lost the meso- and macroporosity present in the precursor, it has a wider microporosity than the activated samples derived from anthracite. Pore size distribution studies and CO_2 isotherms are being conducted to determine the degree of microporosity for the activated samples.

Table 1 lists the BET SA and total pore volume, V_{TOT} , of the activated carbons generated. As expected from the isotherms (Figure 2), the A-90 has the highest SA and V_{TOT} . When comparing samples activated under similar conditions but derived from different precursors, UC-60 and A-60, the activated carbon generated from the anthracite presents the highest SA and V_{TOT} . Figure 3 illustrates that these differences are not due to the precursors, but to the solid yield. Indeed, extremely good correlations were obtained between the solid yields and both the SA and the V_{TOT} , regardless of the precursor. The effect of the different flowrate of steam used to activate the unburned carbon and the anthracite is being investigated.

The activated carbons generated from the anthracite present SA significantly higher than that of previous studies conducted by one of the authors⁶. In fact, the SA of the sample activated after 90 minutes, A-90, presents a SA of 1037 m²/g, compared to that of 610 m²/g after six hours of activation. This is probably due to a combination of the lower flowrates (2 g of water / min vs. 12 g of water / min) and smaller particle size (250-150 µm vs. 1-3 mm) used here, resulting in more favourable conditions for the production of activated carbons.

CONCLUSIONS

The work reported here has demonstrated for the first time the ability of unburned carbon from coal combustion waste to generate activated carbons by steam activation with a high solid yield. All the activated carbons investigated present isotherms Type I that are typical for microporous carbons, regardless of the precursor used for their production. Furthermore, the inherent porosity of the precursor does not seem to limit the surface area, neither the total pore volume of the activated carbons. However, these two properties are strongly related to the solid yields. The nature of the precursor does seem to influence the extent of microporosity, in the sense that anthracite produced activated carbons with narrower microporosity than the one derived from unburned carbon. The molecular sieve properties of the activated carbons generated from anthracites will be reported.

ACKNOWLEDGMENTS

The authors wish to thank the Consortium for Premium Carbon Products from Coal (CPCPC) at The Pennsylvania State University and the Research Council of the Basque Government for financial support.

LITERATURE CITED

- 1 Hong, B.D., 1997, Mining Engineering, **50**, 230.
- 2 Song, C., and Schobert, H.H., 1996, Fuel, **75**, 724.
- 3 Maroto-Valer, M.M., Taulbee, D.N., and Hower, J.C., 1998, Prepr. Am. Chem. Soc. Div. Fuel Chem., **43**, 1014.
- 4 Stewart, B., 1998, 15th Annual International Pittsburgh Coal Conference, CD volume, 1-9.
- 5 Patrick, J.W., 1995, Porosity in carbons, Edward Arnold, London.
- 6 Gergova, K., Eser, S., and Schobert, H.H., 1993, Energy & Fuels, **7**, 661.
- 7 Brunauer, S., Deming, L.S., Deming, W.S., and Teller, E., 1940, J. Amer. Chem. Soc., **62**, 1723.

Table 1. Solid yield, BET surface area and total pore volume of the raw precursors and the activated carbons generated from unburned carbon and anthracite¹.

| | Activation time / min | Solid yield / % weight | BET S.A. / m ² /g | V _{total} / cm ³ /g |
|-------|--------------------------|---------------------------|---------------------------------|--|
| UC | - | - | 40 | - |
| A | - | - | <1 | - |
| UC-60 | 60 | 73 | 332 | 0.15 |
| A-60 | 60 | 59 | 613 | 0.30 |
| A-90 | 90 | 33 | 1037 | 0.47 |

¹ The solid yields and surface areas are expressed in ash free basis.

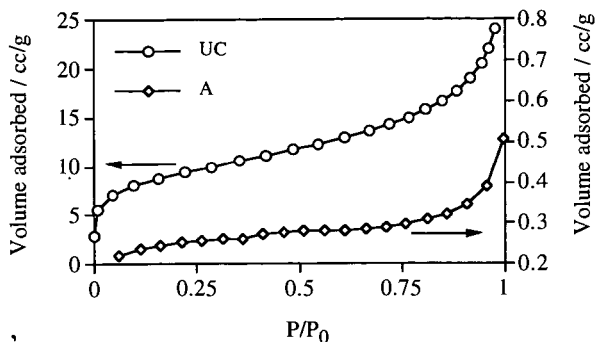


Figure 1 N_2 -77K adsorption isotherms for the raw unburned carbon (UC) and anthracite (A).

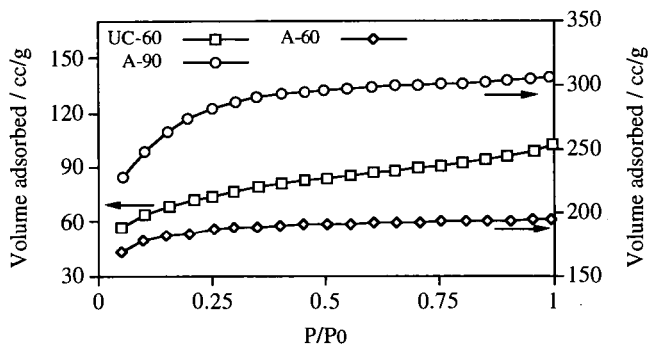


Figure 2 N_2 -77K adsorption isotherms for the steam activated unburned carbon (UC-60) and anthracites (A-60 and A-90).

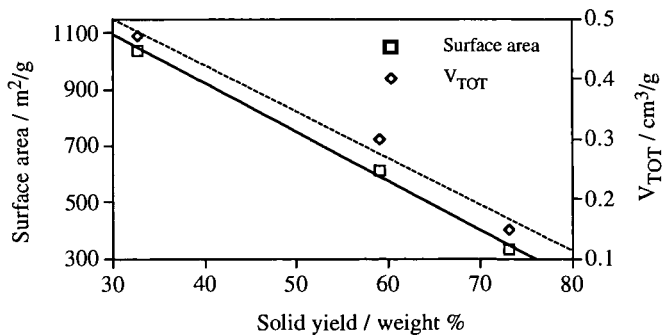


Figure 3 Relationship between solid yields, SA and V_{TOT} for all the activated carbons investigated (UC-60, A-60 and A-90).

CO-COKING: AN ALTERNATIVE PROCESS FOR COAL DERIVED JET FUEL PRODUCTION

Anne E. Fickinger, Mark W. Badger, Gareth D. Mitchell and Harold H. Schobert
The Energy Institute
Coal Utilization Laboratory
The Pennsylvania State University, University Park, PA 16802

Keywords: Coal/resid co-coking, coal derived jet fuels, coke formation.

Introduction

It has been found that coal-derived aviation fuels are more thermally stable than petroleum-derived fuels. This is mainly due to the presence of 2 to 3 ringed aromatic components in the oil fractions, which on further processing yield cycloalkane rich fuels [1,2]. Conventionally, coal-derived fuels were produced via coal liquefaction [3,4]. But due to economic market trends a more viable path to obtain these ringed aromatic components is through co-coking. Co-coking is a thermal process used to upgrade and convert petroleum resid and coal simultaneously. Co-coking involves simulating a delayed coker unit in a refinery while adding coal, so that petroleum resids are upgraded to yield a distribution of products that include oils, gases, and coke. Coal is added to increase oil yields as well as produce the coal-derived aromatic components that make a thermally stable jet fuel.

The delayed coking process involves subjecting a petroleum resid to temperatures of 450 - 500 °C [5,6]. A constant pressure of 10-20 psig within the coke drum is maintained due to the evolution of gaseous products. This process not only produces useful oil products, but also quality coke products depending on the initial feedstock. These conditions produce product yields of 70% liquids, 10% gas, and 20% coke. However, since this process was simulated in batch reactors, the product distribution will vary.

The work presented here represents a continuation of previous studies of co-processing [7].

Experimental

Three high volatile bituminous coals were obtained for the Penn State Coal Sample Bank and Database. The coals were chosen for their extremely high fluidity, as well as their low moisture, and sulfur content. These properties are displayed in Table 1. The samples were ground to a <60 mesh to ensure good contact qualities and then vacuum dried at 110 °C for 2 hours prior to each of the experiments. The petroleum vacuum resid used was a coker feed supplied by BP America.

The reactions were carried out in vertical 25 ml microautoclave reactors with *ca* 6 grams of coker feed and 3 grams of coal (resid/coal ratio of 2:1 by weight) at four temperatures (450, 465, 475, and 500 °C). The reaction length was 2 hours. The reactors were purged with nitrogen to remove any air within the reactors and left at ambient pressure. Once the reaction was complete, the reactors were cooled and the gases that evolved were vented. Any pourable liquid was collected through the stem and later included in the oils (hexane soluble fraction). The products were then removed from the reactor and subjected to a Soxhlet extraction using hexane to remove the oils, toluene to remove the asphaltenes, and finally THF to remove the preasphaltenes. The THF insolubles were then dried in a vacuum oven for 2 hours at 30 °C to remove any excess solvent so the coke product yield could be recorded on a dry weight basis.

The hexane-soluble fractions were subject to analysis by the GC, GC-MS, and the Sim Dis GC. Ultimate analysis was performed on the coke products using a LECO 600 for C, H, and N, and a LECO MAC 400 for proximate analysis to obtain the ash and moisture content to determine the chemical interactions between the coals and the resid. Optical microscopy was also performed to determine how the coal and the resids contributed towards the coke product.

Results and Discussion

Figure 2 shows the GC traces for the four different temperatures for one of the coals used, Powellton coal. By examining this figure the trends described below can be seen. Table 2 shows the percentage yields for the various fractions from co-coking experiments using Powellton, Eagle, and Pittsburgh coal at temperatures between 450 - 500 °C.

The results for the coals and coker feed mixed together at 450 °C, showed high oil yields with relatively high coke yields. However, GC traces showed that the oils contained long-chain paraffins, and not the 2-3 ring aromatics that are precursors to thermally stable jet fuel. The results of the coker feed and the coal at temperatures of 465-475 °C showed an increase in coke production with a decrease in oil yield. GC traces further showed that the oils produced contained the 3-5 ringed aromatic components that could be further processed to desirable precursors. The results of the resid and coal at 500 °C showed a heightened effect of an increase in coke production with a decrease in the oil yield. However, when the GC traces were examined the 1-3 ringed aromatics were the major components, suggesting that the reaction conditions were too severe.

Figure 1 shows the changes in the yield of the solvent fractions for co-coking experiments with Powellton coal. Similar trends for the changes in product yields were observed for the Eagle and Pittsburgh coals. The product yields showed that the coke yield increased with decreasing oil yield. This resulted because the reactors were not vented during the reaction, which caused the volatile gases to build up inside. The higher pressure and sealed environment within the reactor, as well as the longer contact time between the volatile constituents at reaction temperature caused the coke yield to increase to the detriment of the oil yield. This effect was noted previously by Hossain and co-workers [8]. This may be why the yields of the products differ from delayed coking operation yields. Delayed coking is a system that allows the volatiles to be vented off on production, which in turn leads to high oil yields (~70%) and lower coke yields (~20%).

These results indicate that we have a flexibility in our process. Depending on the temperature of operation we can manipulate the product yields and compositions to produce precursors for thermally stable jet fuel. That is, for products with 3-5 ringed aromatics an upgrading/hydrogenation process under severe conditions will produce cycloalkanes in the desired boiling fractions which could be used as thermally stable jet fuels. However, it may be desired that a less severe upgrading process be utilized and therefore a product with 1-3 ringed aromatics would be more advantageous.

Elemental analysis of the coke products has produced some interesting and, as yet, not fully understood results. The general trend noted is that when coal and resid are co-coked, we obtain a product that has a lower H/C ratio (more carbon rich) than when resid is coked alone. This, however, does not unequivocally indicate that the product is of a higher quality. Optical microscopy studies tend to suggest that the presence of the coal changes the way resid coke is formed. Interactions between coal and resid have been noted, which may indicate some dissolution. Initial studies have shown that the optical texture of the cokes produced at 450 °C during co-coking have similar properties of cokes produced from the coking of the resid alone, at temperatures above 475 °C. As to why this is occurring is unclear at present and needs further study.

From the work performed so far in the batch reactor systems, we believe that 465 °C is the best temperature to produce the best quality oil fraction at reasonable yields. Further study will include feed ratio studies, and the effects of reaction length on yields. Alternative feeds, such as decant oil, will also be investigated, with the hope that greater dissolution of the coal will occur while producing different coke products.

References

1. Song, C., Eser, S., Schobert, H.H. and Hatcher, P.G., *Energy and Fuels*, **7**, 234, (1993).
2. Al, W.-C., Song, C., Schobert, H.H. and Aramugam, R., *ACS Div. Fuel Chem. Preprints*, **37**, 4, 1671, (1992).
3. Song, H., and Hatcher, P.G., *ACS Div. Fuel Chem.* **37**, 2, 529, (1992).
4. Lai, W.-C. and Song, C., *Fuel*, **74**, 1436, (1995).
5. Speight, J.G. in "The Chemistry and Technology of Petroleum. 2nd Edition", Marcel Dekker Inc., New York, (1991).
6. Gray, M.R. in "Upgrading of Petroleum Residues and Heavy Oils", Marcel Dekker Inc., New York, (1994).
7. Martin, S.C., Tomic, J. and Schobert, H.H., *ACS Div. Fuel Chem.* **42**, 3, 121, (1997).
8. Hossain, T., Zaman, N., Jahan, S.T., Podder, J. and Rashid, M.A., *J. Mech. Eng. Res. Dev.* **16**, 47, (1993).

Acknowledgments

The authors would like to express their gratitude to the Department of Defense and Air Force Wright-Patterson Laboratory for the funding of this project under contract F33615-98-D2802 delivery order 0003.

Table 1: Properties of the Coals

| | POWELLTON | EAGLE | PITTSBURGH #8 |
|------------------------|-----------|--------|---------------|
| RANK | hVab | hVab | hVab |
| MOISTURE | 6.5 | 6.8 | 2.4 |
| ASH | 5.0 | 5.5 | 10.. |
| %C | 87.6 | 87.3 | 83.3 |
| %H | 5.8 | 5.6 | 5.7 |
| %N | 1.6 | 1.6 | 1.4 |
| %S | 0.9 | - | 1.3 |
| %O | 3.9 | - | 8.4 |
| TEMP. MAX FLUIDITY (C) | 448.0 | 437.0 | 438.0 |
| FLUIDITY (DDPM) | 30000+ | 30000+ | 20002 |

Table 2: Percent yields for the Eagle, Powellton, and Pittsburgh coal at 450, 465, 475, and 500°C

| TEMP (C) | COAL | PERCENT YIELDS | | | | | | |
|----------|------------|----------------|------|-------------|---------------------|------|-------|--------|
| | | GAS | OILS | ASPHALTINES | PRE- ASPHALTINES | COKE | TOTAL | LOSSES |
| 450 | EAGLE | 14.0 | 24.7 | 3.5 | 2.5 | 42.1 | 86.8 | 13.2 |
| | POWELLTON | 12.1 | 32.2 | 17.2 | 4.0 | 37.1 | 102.5 | -2.5 |
| | PITTSBURGH | 12.2 | 19.5 | 4.3 | 3.8 | 44.5 | 84.4 | 15.6 |
| 465 | EAGLE | 22.3 | 13.2 | 2.7 | 4.7 | 50.4 | 93.3 | 6.7 |
| | POWELLTON | 23.6 | 12.5 | 0.7 | 1.6 | 51.8 | 90.1 | 9.9 |
| | PITTSBURGH | 18.0 | 16.9 | 1.8 | 1.0 | 49.1 | 86.9 | 13.1 |
| 475 | EAGLE | 18.3 | 6.5 | 8.0 | 2.3 | 47.6 | 82.7 | 17.3 |
| | POWELLTON | 9.1 | 7.7 | 0.6 | 2.4 | 36.5 | 56.4 | 43.6 |
| | PITTSBURGH | 24.9 | 12.5 | 1.4 | 4.5 | 51.2 | 94.4 | 5.6 |
| 500 | EAGLE | 17.0 | 5.4 | 0.3 | 4.4 | 48.5 | 75.6 | 24.4 |
| | POWELLTON | 28.3 | 6.7 | 0.3 | 2.2 | 50.5 | 87.9 | 12.1 |
| | PITTSBURGH | 28.5 | 6.3 | 0.5 | 2.7 | 50.9 | 89.0 | 11.0 |

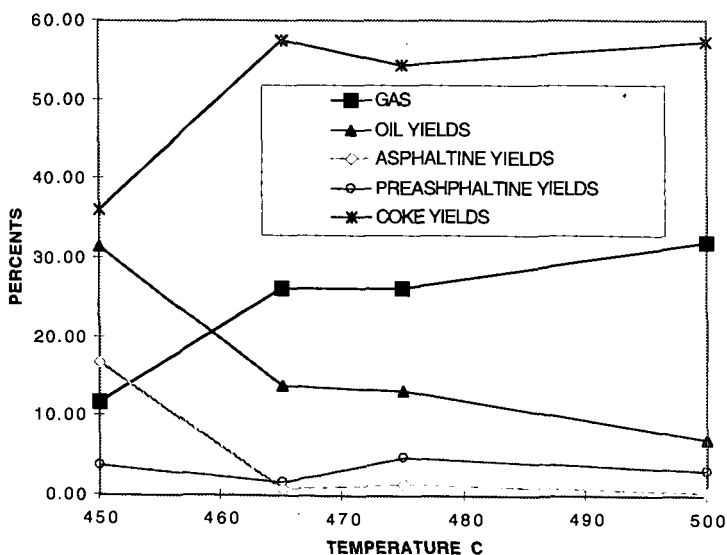


Figure 1: The product yield trends for the Powellton coal at the four temperatures

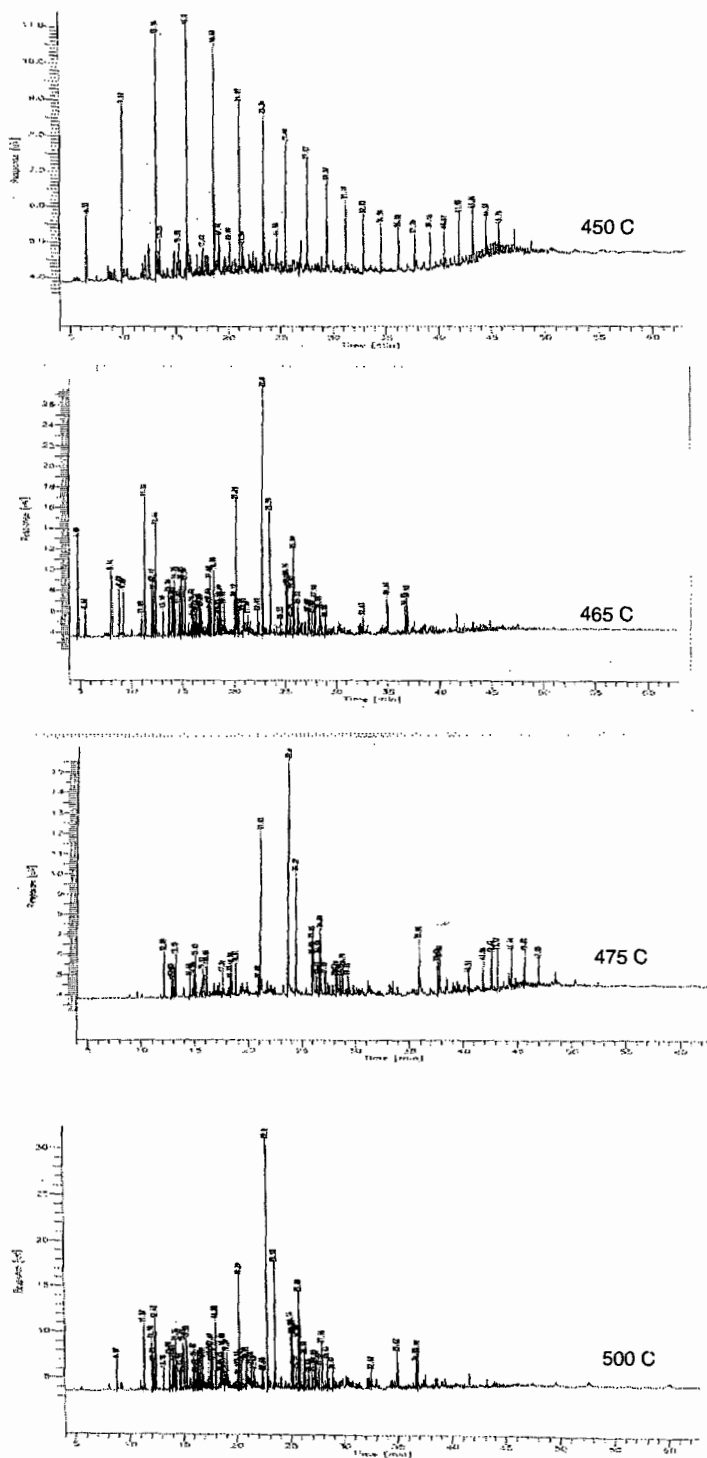


Figure 2: GC Traces for the Powellton coal and coker feed at the four various temperatures [X Axis: time (min) Y Axis: Response (uV)]

ADVANCES IN COAL CLEANING

Ilham Demir, Latif A. Khan, and John M. Lytle
Illinois State Geological Survey, 615 E. Peabody Drive, Champaign, Illinois 61820

Keywords: advanced coal cleaning, flotation, gravity separation

INTRODUCTION

Run-of-mine coal generally has an ash content of 5-40% and a sulfur (S) content of 0.3-8% depending on the geologic conditions and mining technique used. Coal cleaning, therefore, is often required to remove excessive impurities for efficient and environmentally safe utilization of coal. In the US, the coal cleaning is most common at Eastern and Midwestern mines. Over 90% of the 267 US plants operated in 1998 were in eight Eastern and Midwestern states: West Virginia, 70; Kentucky, 56; Pennsylvania, 41; Virginia, 23; Indiana, 16; Illinois, 15; Ohio, 12; and Alabama, 11.¹

Current commercial coal cleaning methods are invariably based on physical separation; chemical and biological methods tend to be too expensive. Typically, density separation is used to clean coarse coal while surface property-based methods are preferred for fine coal cleaning. In the density-based processes, coal particles are added to a liquid medium and then subjected to gravity or centrifugal forces to separate the organic-rich (float) phase from the mineral-rich (sink) phase. Density-based separation is the most common coal cleaning method and is commercially accomplished by the use of jigs, mineral spirals, concentrating tables, hydrocyclones, and heavy media separators. The performance of density-based cleaning circuits is estimated by using laboratory float-sink (F-S) tests. In the surface property-based processes, ground coal is mixed with water and a small amount of collector reagent is added to increase the hydrophobicity of coal surfaces. Subsequently, air bubbles are introduced in the presence of a frother to carry the coal particles to the top of the slurry, separating them from the hydrophilic mineral particles. Commercial surface property-based cleaning is accomplished through froth or column flotation. To estimate the performance of flotation devices, a laboratory test called release analysis is used.²⁻⁵

Theoretically, the efficiency of physical cleaning should increase as particle size decreases because of the improved liberation of the mineral matter from the coal matrix. Therefore, recent research on advanced coal cleaning has focused on improving fine-coal cleaning. Column flotation devices developed since the 1980s can remove most of the impurities from finely-ground coal.⁶⁻⁸ Likewise, advanced gravity separators, developed mainly for metal mining industries, were shown in recent years to have a good potential for improving the cleaning of finely-ground coal.^{9,10} This paper discusses work on physical fine-coal cleaning conducted at the Illinois State Geological Survey (ISGS) and reviews work conducted elsewhere on the similar subject.

LABORATORY TESTS TO ASSESS FURTHER CLEANABILITY OF ILLINOIS COALS

As-shipped (cleaned) coals from eight coal preparation plants in Illinois were selected to assess the further cleanability of conventionally cleaned coals.¹¹ The criteria for sample selection were based on the representation of the main producing seams, high and low S coals, high and low ash coals, and different geographic regions of the Illinois coal field. Therefore, the interpretations reported here should apply to most marketed coals from Illinois mines. Release analysis (RA) and F-S test data were generated to estimate the beneficiation of the eight coals, at -60 mesh (<250 μ m) particle size and 80%-combustibles recovery.

Froth Flotation Cleanability The RA tests indicated that ash yield and S content of Illinois coals could be reduced substantially beyond conventional cleaning through the use of froth flotation or column flotation. The ash yield was reduced by 24-69% and S content by 4-24% relative to the parent coals (Table 1). The proportion of the total S removed increased with increasing ratio of pyritic to organic S.¹¹ Both the absolute and relative reduction of ash yield tended to increase with the amount of ash yield in the parent coal.

The RA separation resulted also in significant reductions for the contents of most elements that are classified as hazardous air pollutants or HAPs (Table 1). In some cases, reductions for HAPs approached or exceeded the reductions for ash. Reductions for Mn and P approached or exceeded reductions for ash in almost all cases. A substantial portion of Mn is thought to occur in solid solution in calcite, and P is associated, perhaps primarily, with apatite in coal. Most of the calcite and some of the apatite occur as cleat fillings, nodules, and/or partings^{12,13} which are more easily removed during coal cleaning than finely disseminated minerals.

Float-Sink Washability The F-S washability data indicated that density (gravity)-based physical fine-coal cleaning can be quite effective in further reducing ash and S contents of marketed Illinois coals (Table 1). Clean coals having ash yields of 3.6-6.8% can be produced from the eight coals. The ash yields were reduced by 47-75% relative to conventional cleaning. The S content of the eight clean F-S products varied between 0.73% and 3.28%, representing a 21-42% reduction. Comparison of the S data from this study with the data on S forms of feed coals¹⁴ indicated that the S remaining in the clean F-S products is overwhelmingly organic S; most of the inorganic S was

removed during the F-S process.

The clean F-S products had much smaller HAP contents than the conventionally cleaned feed coals, with a few exceptions (Table I). Reductions of As, Cd, Hg, Mn, and P contents exceeded reductions for ash in almost all cases. Arsenic, Cd, and Hg are associated mostly with sulfide minerals¹⁵ that have high specific gravities and, therefore, respond to gravity separation efficiently. Minerals containing substantial amounts of Mn (calcite) and P (apatite) also showed efficient response to the F-S separation, as well as RA, because, as indicated earlier, these minerals tend to occur as relatively coarse grains in cleat fillings, nodules, or partings. Because As, Cd, F, Hg, Pb, and Se have relatively high atmospheric mobilities during coal combustion^{15,16}, achieving high removal values for these elements is important from an environmental point of view. Those HAPs that were reduced less than the ash apparently occurred either in organic form or in extremely fine mineral particles disseminated in the organic matter which were not liberated by grinding the coals to the selected particle size. This may be the case for Be, Sb and U in some of the samples. However, the elements that exhibited enrichment or relatively low cleanabilities either have low concentrations in Illinois coals or low atmospheric mobilities during coal combustion^{15,16} which would result in low environmental risk associated with their emissions.

In general, the beneficiation of the eight coals through the use of the F-S test was considerably greater than the beneficiation obtained through the RA test (Figure 1). The difference between the F-S and RA results was particularly large for some samples (Table I). The effectiveness of the F-S separation for the most environmentally critical elements, S and Hg, is particularly important. Because Be tended to stay largely with the organic matter, it was generally enriched more in the F-S products than in the RA products. The comparison of the F-S and RA data suggested that RA can estimate the performance of standard flotation circuits but probably not the performance of advanced gravity separators and some advanced flotation devices. Float-sink tests appear to be more suitable to estimate the ultimate cleanability of coal through the use of advanced physical cleaning.

PILOT SCALE TESTS WITH ISGS FROTH WASHER DEVICE

A froth washer device was developed at the ISGS to improve the performance of both subaeration cells and flotation columns.¹⁷ The ISGS froth washer enables the washing and quick removal of fine contaminants into a separate stream of a flotation circuit. Tests conducted on IBC-112 coal in the Illinois Basin Coal Sample Program indicated that a subaeration cell equipped with the ISGS froth washer removed more ash-forming minerals and S from the coal than a packed column device (Figure 2). The performance of the modified subaeration cell generally approached the ultimate cleanability predicted from F-S tests and the so-called advanced flotation washability analysis (AFW) as defined elsewhere.¹⁷ Using the subaeration cell with the ISGS washer, a second set of tests was performed on a sample of preparation plant fines containing 43.5% ash, 4.2% total S, 2.0% pyritic S, and having a heating value of 7934 Btu/lb. The optimized performance of the subaeration cell with the ISGS washer at a throughput of 50 lb/hr/ft² approached that of the AFW process, resulting in 75% ash rejection and 45% pyritic S rejection at 83%-combustibles recovery.

PILOT AND FULL-SCALE TESTS WITH ENHANCED GRAVITY SEPARATORS

It has been reported that gravity-based separation can potentially be superior to surface property-based separation for reducing the pyrite content of coal.¹⁵ Honaker and co-workers^{9,10,19-21} evaluated the application of enhanced gravity separation to pilot and full-scale coal cleaning. Using a dense medium Falcon gravity separator, the ash yield and pyritic S content of a 28x325 mesh coal collected from a preparation plant treating Illinois Herrin (No. 6) Coal were reduced from 17.5% to 3.5% and from 0.55% to 0.15%, respectively, while recovering 87.8% of the combustible material.¹⁹ Comparison with AFW data suggested that the dense medium Falcon Concentrator can potentially outperform the best flotation technology available. Pilot scale tests with a Falcon Concentrator, a Knelson Concentrator, and an Altair Jig indicated that they were all effective for cleaning a 28x400 mesh coal sample from the Illinois Springfield (No. 5) Coal.²⁰ Typically, 80% of the ash and 70% of the total S were rejected at 85% recovery of the combustible material. During full-scale testing with a mass flow rate of 100 t/hr, the Falcon Concentrator efficiently cleaned a refuse pond coal sample.²⁰ The ash yield was reduced from 22% to 8% for the 28x100 mesh fraction and from 32% to 15% for the 100x500 mesh fraction, while recovering a little over 80% of the combustible material. Nearly 90% of the pyritic S was rejected, resulting in the reduction of the total S content of both fractions from 7.9% to 2.7%.

OTHER PHYSICAL METHODS FOR ADVANCED COAL CLEANING

Other physical cleaning methods, including selective agglomeration, heavy medium cycloning, and dry separation with electrical and magnetic methods, have been discussed by Couch.^{22,23} Selective agglomeration and advanced cycloning have the high probability of commercialization, particularly for reducing S content of coal.²³ In selective agglomeration, the coal is mixed with oil. The oil wets the surface of coal particles and thus causes them to stick together to form agglomerates. The agglomerated coal particles are then separated from the mineral particles that stay in suspension because they do not attract oil to their surfaces. A version of selective agglomeration, called the Otisca T-process, was reported to reduce the ash content of some coals, ground to about 2 μ m,

below 1% with a high recovery of the heat content.²⁴ Conventional cycloning has been used for many years for cleaning relatively coarse coal and considered for fine coal cleaning only in recent years. Coal and heavy medium enters the conical-shape cyclone tangentially near the top. As the cyclone spins around its axis, impurities move downward along the walls and exit through the bottom opening while coal particles move upward near the center and exit from the top. Dry methods that take advantage of the differences between electrical or magnetic properties of minerals and coal particles have not developed enough for commercial applications.

COST OF ADVANCED COAL CLEANING

Progress in fine-coal cleaning has been significant, but the dewatering and material handling stages of the process can be difficult and are expensive. Therefore, the economic and environmental benefits of the final product must justify the cost. Newman et al.²⁵ estimated the cost of advanced cleaning to be \$12/t for run-of-mine coals containing 1-8% S if 90% pyritic S rejection is to be achieved. It is not clear whether dewatering and fine-particle handling costs were included in these estimates. The total cost of advanced cleaning, including dewatering and pelletization (or briquetting), might be \$22-27.5/t.²⁶ One should, however, keep in mind that the product of advanced coal cleaning is a low-ash, low-S, and high-heating value fuel. Therefore, some expenses of the advanced coal cleaning can be offset by (1) reduction in transportation cost per unit of heating value of coal, (2) elimination of milling cost at power plants, and (3) reduced maintenance cost of power plants related to fouling, slagging, and other wear and tear. Furthermore, the pelletization or briquetting costs may be eliminated if the advanced cleaning product is used as a coal-water fuel to replace oil in oil-fired boilers. Transporting coal-water fuels through pipelines would provide further cost-cutting benefits. Although the application of advanced fine-coal cleaning is currently limited, its widespread commercialization may eventually take place, depending on further improvements in technology, supply and demand for different fuels, and future environmental regulations.

CONCLUSIONS

Release analysis (RA) and float-sink (F-S) test data for selected samples suggested that advanced physical cleaning at -60 mesh particle size and 80%-combustibles recovery can potentially reduce the ash yield and S content of Illinois coals up to 75% and 42%, respectively, beyond conventional cleaning. As a result, some of the clean products would have ash yields of <4% and S content of <1%. The F-S process was generally more effective than the RA process for cleaning the samples. The average F-S reductions for HAPs were (in %): As(67), Cd(78), Hg(73) Mn(71), P(66), Co(31), Cr(27), F(39), Ni(25), Pb(50), Sb(20), Se(39), Th(32), and U(8). Beryllium was generally enriched in the clean RA and F-S products. However, elements with relatively low removal or enrichment values would have very little, if any, environmental impact because they either occur in very small quantities in Illinois coals or are fixed largely in coarse ash and slag during coal combustion.

Two advanced cleaning technologies tested on Illinois coals in recent years yielded promising results. The performance of a froth washer device developed at the ISGS to improve the performance of both subaeration cells and flotation columns generally approached the ultimate cleanability predicted from laboratory F-S tests. Pilot and full-scale tests with advanced gravity separators, performed at Southern Illinois University, suggested that such equipment can potentially outperform even the best flotation technology available.

The estimated cost of advanced fine-coal cleaning ranges from \$12 to \$28 per ton, which is uneconomical under current conditions. However, some expenses of advanced coal cleaning can be offset by reduction in transportation cost, elimination of milling cost at power plants, and reduced maintenance cost of power plants. Widespread commercialization of advanced coal cleaning technologies depends on further improvements in technology, supply and demand for different fuels, and future environmental regulations.

REFERENCES

1. Fisor S. and Fischer M. (1998) U.S. Preparation Plant Census. Coal Age, September 1988, p. 70-76.
2. Dell C. C., Bunyard M. J., Rickelton W.A., and P.A. Young P. A. (1972) Release analysis: a comparison of techniques. Trans. IMM (C. Mineral Process. Extrac. Metall.) 81, C89-96.
3. Forrest W. R., Jr. (1990) Processing of Sec High-sulfur Coals using Microbubble Column Flotation. M.S. Thesis, Virginia Polytechnic Institute and State Univ., Blacksburg, VA.
4. Honaker R. Q. and Paul B. C. (1994) A comparison study of column flotation technologies for the cleaning of Illinois coal. Interim Report to the Illinois Clean Coal Institute, Cartersville, IL.
5. Demir I., Ruch R. R., Harvey R. D., Steele J. D., and Khan S. (1995) Washability of Trace Elements in Product Coals from Illinois Mines. Open File Series 1995-8, Illinois State Geological Survey, Champaign, IL.
6. Yang D. C. (1990) Packed-bed column flotation of fine coal. Part I: laboratory tests and flotation circuit design. Coal Preparation, vol. 8, p19-36.
7. Yoon R-H, Luttrell G. H., Adel G. T., Mankosa M. J. (1990) The application of Microcell column flotation to fine coal cleaning, Presented at Engineering Foundation Conference on Fine Coal Cleaning, Palm Coast, FL, December 2-7, 1990.
8. Kennedy A. (1990) The Jameson flotation cell. Mining Magazine, vol. 163, p. 281-285.
9. Paul B. C. and Honaker R. Q. (1994) Production of Illinois Base Compliance Coal Using Enhanced

- Gravity Separation. Final Technical Report to the Illinois Clean Coal Institute, Carterville, IL.
10. Honaker R. Q., Wang D. and Ho H. (1996) Application of the Falcon Concentrator for fine coal cleaning. *Minerals Engineering*, vol 9(11), p. 1143-1156.
 11. Demir I. (1998) Removal of ash, sulfur, and trace elements of environmental concern from eight selected Illinois coals. *Coal Preparation*, vol. 19, p. 271-296.
 12. Rao C. P. and Gluskoter H. J. (1973) Occurrence and Distribution of Minerals in Illinois Coals. Circular 476, Illinois State Geological Survey, Champaign, IL, 1973.
 13. Harvey R. D., R.A. Cahill R. A., Chou C.-L., and Steele J. D. (1983) Mineral Matter and Trace Elements in the Herrin and Springfield Coals, Illinois Basin Coal Field. Contract/Grant Report: 1983-4, Illinois State Geological Survey, Champaign, IL.
 14. Demir I., Harvey R. D., Ruch R. R., Damberger H. H., Chaven C., Steele J. D., and Frankie W. T. (1994) Characterization of Available (Marketed) Coals From Illinois Mines. Open File Series 1994-2, Illinois State Geological Survey, Champaign, IL.
 15. Demir I., Ruch R. R., Damberger H. H., Harvey R. D., Steele J. D., and Ho K. K. (1998). Environmentally critical elements in channel and cleaned samples of Illinois coals. *Fuel*, 77: 95-107.
 16. Davidson R. M (1996) Trace elements in coal. IEA Coal Research, IECPER/21, London.
 17. Khan L. A. and Lytle J. M. (1997) Testing of Improved Froth Washing & Drainage Device for Flotation Machines. Final Technical Report to the Illinois Clean Coal Institute, Carterville, IL
 18. Adel G. T., Wang D., and Yoon R. H. (1991) Washability Characterization of fine coal. *Proc. 8th Annual International Pittsburgh Coal Conference*, 204-209.
 19. Honaker R. Q., Rajan B. J., Mohanty M. K., and Sing N. (1998) A Novel High Efficiency Enhanced Gravity Separation Using Dense Medium. Mid-year Technical Report to the Illinois Clean Coal Institute, Carterville, IL
 20. Honaker R. Q. and Govindarajan B. (1998) Enhanced gravity concentration: An effective tool for fine coal cleaning. *Inside Coal Research*, vol. 4(3), p. 2-3, Coal Research Center, Southern Illinois University, Carbondale, IL.
 21. Mohanty M. K. and Honaker R. Q. (1998) Evaluation of the Altair centrifugal jig for fine particle separations. Reprint 98-169, SME Annual Meeting, Orlando, FL.
 22. Couch G. R. (1991) Advanced coal cleaning technology. IEA Coal Research, IEACR/44, London.
 23. Couch G. R. (1995) Power from coal - where to remove impurities? IEA Coal Research, IEACR/82, London.
 24. Keller D. V. and Bury W. M. (1990) The demineralization of coal using selective agglomeration by the T-process. *Coal Preparation*, vol. 8(1/2), p. 1-17.
 25. Newman J., Kanteseria P., and Huttenhain H. (1994) An evaluation of physical coal cleaning plus FGD for coal fired utility applications. In: *Proceedings of the 11th International Conference on Coal Utilization and Fuel Systems* 3/21-3/24/1994, Clearwater, FL, p. 317-327.
 26. Smouse S. M. (1994) To clean or not to clean? A technical and economic analysis of cleaning Pittsburgh seam coal. In: *Proc. of the Engineering Foundation Conference on the Impact of Coal Fired Power Plants*, 6/20-6/25/1993, Solihull, UK. Taylor&Francis, Washington D.C., p. 189-217.

Table 1. Analyses of the eight as-shipped Illinois coals and their clean RA and F-S products at -60 mesh size and 80%-combustibles recovery. All values are on a dry basis.

| Feed Lab no. | Feed or Cleaning product | Heating value (Btu/lb) | Ash yield (%) | S (%) | HAP elements (mg/kg) | | | | | | | | | | | | | | | |
|--------------------|--------------------------|------------------------|---------------|-------|----------------------|------|-------|-----|-----|-----|------|-----|-----|-----|-----|-----|-----|-----|-----|--|
| | | | | | As | Be | Cd | Co | Cr | F | Hg | Mn | Ni | P | Pb | Sb | Se | Th | U | |
| C32778 | feed | 12709 | 9.80 | 1.60 | 10 | 2.2 | 0.60 | 4.6 | 12 | 70 | 0.04 | 38 | 31 | 87 | 14 | 2.2 | 1.5 | 1.5 | 0.9 | |
| | RA product | 13622 | 5.63 | 1.21 | 5.8 | 2.6 | <0.2 | 4.0 | 9.7 | 57 | 0.05 | 13 | 29 | 39 | 8 | 2.2 | 1.0 | 1.3 | 1.1 | |
| | F-S product | 13962 | 4.79 | 1.19 | 2.9 | 4.6 | <0.08 | 3.8 | 9.4 | 59 | 0.01 | 12 | 29 | 39 | 7 | 2.2 | 1.0 | 1.2 | 1.3 | |
| C32782 | feed | 12503 | 11.62 | 3.90 | 2.4 | <1.0 | 0.40 | 1.6 | 14 | 78 | 0.07 | 55 | 7 | 87 | <6 | 0.5 | 1.9 | 1.1 | 1.3 | |
| | RA product | 13448 | 8.97 | 3.65 | 1.3 | 1.3 | <0.2 | 1.2 | 10 | 66 | 0.04 | 18 | 6 | 31 | 4 | 0.4 | 1.3 | 0.9 | 1.4 | |
| | F-S product | 13797 | 5.89 | 2.99 | 0.9 | 2.2 | <0.1 | 1.2 | 9.7 | 63 | 0.02 | 15 | 5 | 28 | 3 | 0.4 | 1.0 | 0.9 | 1.4 | |
| C32785 | feed | 12741 | 9.75 | 4.17 | 2.3 | 1.5 | 0.40 | 2.6 | 17 | 115 | 0.07 | 39 | 18 | 131 | <5 | 0.4 | 3.9 | 1.3 | 1.8 | |
| | RA product | 13538 | 6.54 | 4.00 | 1.6 | 2.0 | <0.3 | 2.0 | 12 | 89 | 0.07 | 17 | 16 | 35 | 7 | 0.4 | 2.8 | 1.1 | 1.8 | |
| | F-S product | 14029 | 4.38 | 3.28 | 0.7 | 1.5 | 0.10 | 1.8 | 12 | 87 | 0.01 | 12 | 14 | 31 | 3 | 0.2 | 1.9 | 1.0 | 1.4 | |
| C32815 | feed | 12422 | 12.03 | 3.73 | 3.0 | <1.0 | <0.2 | 2.7 | 14 | 88 | 0.06 | 61 | 10 | 44 | 12 | 0.6 | 2.1 | 1.7 | 1.9 | |
| | RA product | 13538 | 8.72 | 3.23 | 1.8 | 1.4 | <0.3 | 2.1 | 13 | 80 | 0.05 | 19 | 8 | 17 | 7 | 0.5 | 1.8 | 1.4 | 1.9 | |
| | F-S product | 13933 | 5.01 | 2.80 | 0.9 | 2.1 | <0.09 | 1.7 | 11 | 89 | 0.02 | 18 | 7 | 13 | 7 | 0.4 | 1.0 | 1.2 | 1.9 | |
| C32786 | feed | 12120 | 16.10 | 1.05 | 9.8 | 1.0 | 0.90 | 8.5 | 19 | 123 | 0.06 | 41 | 24 | 87 | 31 | 1.0 | 2.0 | 3.0 | 1.0 | |
| | RA product | 12908 | 10.59 | 0.82 | 8.7 | 1.9 | <0.4 | 6.5 | 17 | 95 | 0.06 | 17 | 19 | 44 | 27 | 0.9 | 1.9 | 2.4 | 0.7 | |
| | F-S product | 14277 | 6.80 | 0.73 | 4.2 | 1.7 | 0.04 | 5.5 | 14 | 51 | 0.02 | 11 | 19 | 32 | 14 | 1.0 | 1.3 | 1.8 | 0.7 | |
| C32662 | feed | 13525 | 7.00 | 1.51 | 14 | 1.4 | <0.3 | 4.4 | 10 | 83 | 0.08 | 15 | 17 | 175 | 23 | 1.0 | 1.3 | 1.9 | 1.9 | |
| | RA product | 13892 | 4.58 | 1.33 | 9.4 | 1.9 | <0.2 | 2.8 | 8.8 | 65 | 0.08 | 8.6 | 15 | 100 | 17 | 0.9 | 1.1 | 1.5 | 1.8 | |
| | F-S product | 14143 | 3.87 | 1.11 | 5.2 | 2.7 | <0.07 | 2.8 | 7.8 | 43 | 0.02 | 8.0 | 12 | 74 | 14 | 0.8 | 0.9 | 1.2 | 1.8 | |
| C32781 | feed | 13773 | 9.71 | 3.02 | 4.3 | <1.0 | 0.50 | 2.7 | 12 | 104 | 0.11 | 37 | 11 | 44 | 46 | 1.4 | 2.5 | 1.2 | 2.0 | |
| | RA product | 13456 | 7.41 | 2.86 | 2.8 | 1.1 | <0.3 | 1.8 | 11 | 63 | 0.10 | 18 | 11 | 28 | 28 | 1.0 | 1.6 | 1.1 | 1.8 | |
| | FS product | 13915 | 5.19 | 2.04 | 1.4 | 1.1 | <0.09 | 1.7 | 9.9 | 67 | 0.04 | 10 | 8 | 13 | 19 | 1.0 | 1.3 | 0.9 | 1.5 | |
| C32783 | feed | 12402 | 14.14 | 1.64 | 33 | 1.2 | <0.2 | 5.5 | 13 | 124 | 0.13 | 39 | 22 | 175 | 36 | 1.2 | 1.1 | 1.8 | 0.8 | |
| | RA product | 13947 | 4.35 | 1.28 | 16 | 1.2 | <0.2 | 4.4 | 8.0 | 71 | 0.09 | 7.5 | 18 | 96 | 28 | 1.2 | 1.0 | 1.0 | 0.5 | |
| | F-S product | 14151 | 3.59 | 0.95 | 6.4 | 2.0 | <0.06 | 3.7 | 7.0 | 38 | 0.03 | 8.0 | 15 | 57 | 14 | 1.1 | 0.9 | 0.8 | 0.8 | |
| RA mean %change* | | 7 | -40 | -14 | -39 | 32 | -26 | -25 | -19 | -26 | -9 | -63 | -13 | -54 | -24 | -11 | -21 | -20 | -9 | |
| RA min. %change** | | 2 | -24 | -4 | -30 | 0 | -13 | -7 | -9 | 0 | -51 | 0 | -41 | -13 | 0 | -5 | -8 | 0 | 0 | |
| RA max. %change** | | 12 | -69 | -24 | -46 | 90 | -67 | -36 | -38 | -43 | -43 | -81 | -21 | -73 | -43 | -29 | -33 | -44 | -38 | |
| F-S mean %change* | | 10 | -55 | -28 | -67 | 74 | -77 | -31 | -27 | -39 | -73 | -71 | -25 | -66 | -50 | -20 | -39 | -32 | -8 | |
| F-S min. %change** | | 1 | -47 | -21 | -57 | 0 | -55 | -17 | -18 | -16 | -64 | -60 | -6 | -55 | -39 | 0 | -18 | -18 | 0 | |
| F-S max. %change** | | 18 | -75 | -42 | -75 | 120 | -98 | -37 | -46 | -69 | -66 | -79 | -32 | -76 | -61 | -50 | -52 | -56 | -44 | |

* Mean percentage decrease (negative values) or increase (positive values) in heating value, ash yield, or elemental concentrations for the eight coals. %change for each coal = ((Feed value - Product value)/(Feed value))x100. For values below detection limits, the upper limits were used in the computations.

**Absolute change, regardless of sign.

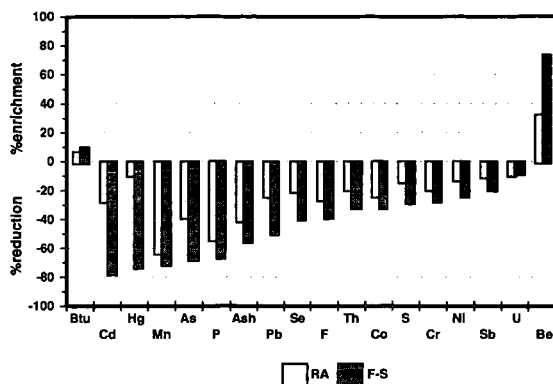


Figure 1. Average changes in heat content (Btu), ash yield, and concentrations of S and HAPs of the eight selected samples of as-shipped Illinois coals as a result of release analysis (RA) and float-sink (F-S) separations at -60 mesh particle size and 80%-combustibles recovery.

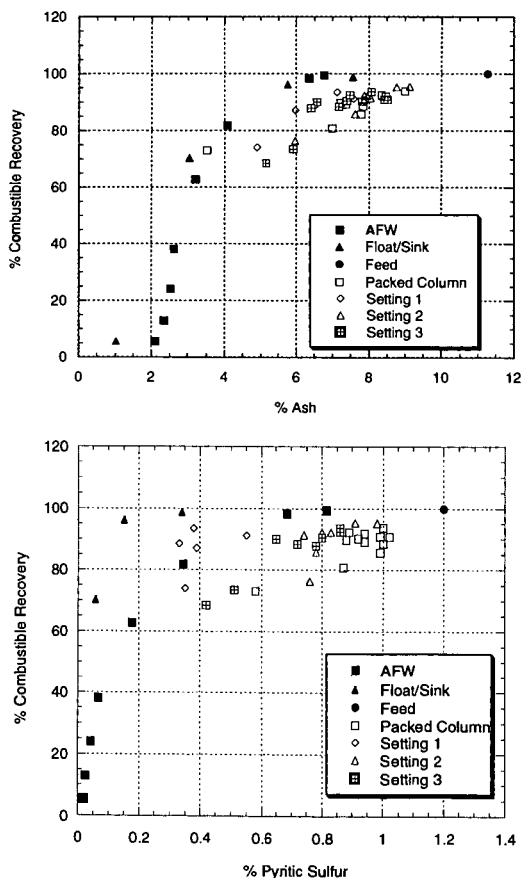


Figure 2. Ash and pyritic S vs. combustible recovery for cleaning IBC-112 ground to 90% -200 mesh using a subaeration cell with the ISGS washer at various settings. For each test, 2 lb/ton kerosene and 2 lb/ton M650 were used.